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E-002/GR-89-865

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

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| In the Matter of the Petition of Northern States Power Company (NSP) for Authority to Increase Its Rates for Electric Service in Minnesota | FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION - PART I (REVENUE REQUIREMENTS) |

The above-captioned matter came on for evidentiary hearing before Administrative Law Judge Richard C. Luis at the Large Hearing Room of the Public Utilities Commission, 780 American Center Building, St. Paul, Minnesota on April 9-13, April 16-20, and April 23-26, 1990. The record in this matter closed on July 2, 1990.

Public hearings for the purpose of receiving the comments and questions of affected ratepayers were held as follows (approximate attendance): March 6 -- Dilworth (17); March 7 -- St. Cloud (28); March 12 -- Coon Rapids (26); March 13 -- St. Paul (43); March 14 -- Minneapolis (44); March 20 -- Winona (23); and March 21 -- Mankato (60). Public comments were taken at the hearings from a total of 46 witnesses. Northern States Power made presentations at each hearing, and appearances were made at various locations by Intervenors Department of Public Service, Office of the Attorney General, Minnesota Senior Federation, and North Star Steel. At least one Public Utilities Commissioner attended each hearing, except in St. Cloud (due to inclement weather). At least one member of the Commission Staff attended each hearing. Members of the public were allowed to file written comments through May 16, 1990.

Appearances at the evidentiary hearing were as follows: David A. Lawrence and Michael Hanson, Northern States Power Company, 414 Nicollet Mall, Minneapolis, Minnesota 55401 and Samuel L. Hanson, Briggs and Morgan, 2400 IDS Center, Minneapolis, Minnesota 55402, appeared on behalf of NSP; Byron E. Starns and James J. Bertrand, Leonard, Street and Deinard, Suite 2300, 150 South Fifth Street, Minneapolis, Minnesota 55402, appeared on behalf of Minnesota Energy Consumers (MEC); Peggy Wells Dobbins, 915 Aduana Avenue, Coral Gables, Florida 33146, appeared on behalf of Champion International (Champion); Maurice A. Frater, P.O. Box 1166, Harrisburg, Pennsylvania 17108, appeared on behalf of Union Carbide; John A. Knapp and Lloyd W. Grooms, Winthrop and Weinstine, 3200 Minnesota World Trade Center, 30 East Seventh Street, St. Paul, Minnesota 55101, appeared on behalf of Metalcasters of Minnesota (Metalcasters); Garrett A. Stone, Ritts, Brickfield and Kaufman, Watergate 600 Building, Suite 915, Washington, D.C. 20037-2474, appeared on behalf of North Star Steel Company (North Star); Glenn E. Purdue, Messerli and Kramer, 1500 Northland Plaza Building, 3800 West 80th Street, Minneapolis, Minnesota 55431-4409, appeared on behalf of Suburban Rate Authority; Thomas J. Weyandt, Assistant City Attorney, 647 City Hall, St. Paul, Minnesota 55102, appeared on behalf of the City of St. Paul, the Board of Water Commissioners of the City of St. Paul and the Municipal Pumpers Association (City or Pumpers); Elmer Scott and Kenneth Zapp, 1855 University Avenue West, St. Paul, Minnesota 55104, appeared on behalf of the Minnesota Senior Federation (Seniors); George M. Crocker and Bruce Drew, 3394 Lake Elmo Avenue North, Lake Elmo, Minnesota 55042, appeared on behalf of the North American Water Office (NAWO); William G. Flynn and David Sasseville, Lindquist and Vennum, 4200 IDS Center, 80 South 8th Street, Minneapolis, Minnesota 55402, appeared on behalf of the St. Paul Chamber of Commerce (Chamber); Corey Ayling, O'Connor and Hannan, 3800 IDS Center, 80 South 8th Street, Minneapolis, Minnesota 55402, appeared on behalf of the Minnesota Retail Merchants Association; Miggie E. Cramblitt, Corporate Secretary, Minnegasco, Inc., 201 South 7th Street, Minneapolis, Minnesota 55402, appeared on behalf of Minnegasco; William M. Mahlum and Christina Stalker, 2222 North Central Life Tower, 445 Minnesota Street, St. Paul, Minnesota 55101, appeared on behalf of District Energy of St. Paul, Inc; Gary Cunningham, Dennis Ahlers and Julia Anderson, Special Assistant Attorneys General, 340 Bremer Tower, Seventh Place and Minnesota Street, St. Paul, Minnesota 55101, appeared on behalf of the Office of Attorney General (OAG); Joan C. Peterson, Mary Jo Murray and Eric F. Swanson, Special Assistant Attorneys General, 1100 Bremer Tower, Seventh Place and Minnesota Street, St. Paul, Minnesota 55101, appeared on behalf of the Minnesota Department of Public Service (DPS); and Susan MacKenzie, Betsy Engelking, Dianne Sorrells and Janet Gonzalez, Rate Analysts and Susan Holupchinski and Louis Sickmann, Financial Analysts, 780 American Center Building, 150 East Kellogg Boulevard, St. Paul, Minnesota 55101, appeared on behalf of the Staff of the Public Utilities Commission. Margie Hendriksen and Jon E. Kingstad, Special Assistant Attorneys General, 780 American Center Building, 150 East Kellogg Boulevard, St. Paul, Minnesota 55101, served as Staff counsel.

Notice is hereby given that, pursuant to Minn. Stat. 14.61, and the Rules of Practice of the Public Utilities Commission and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed within 20 days of the mailing date hereof with the Executive Secretary, Minnesota Public Commission, 160 East Kellogg Blvd., St. Paul, Minnesota 55101. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions and Order should be included and copies thereof shall be served upon all parties. If desired, a reply to exceptions may be filed and served within 10 days after the service of the exceptions to which reply is made. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who requests such argument. Such request must accompany the filed exceptions or reply, and an original and 13 copies of each document should be filed with the Commission.

The Minnesota Public Utilities Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that said recommendation has no legal effect unless expressly adopted by the Commission as its final Order.

## STATEMENT OF ISSUES

Whether Northern States Power Company should be authorized to increase its rates for electrical utility service to customers in Minnesota by $120,782,000 and to collect revenues in accordance with the rate design proposed by NSP.

Based upon all the proceedings herein, the Administrative Law Judge makes the following:

## FINDINGS OF FACT

### JURISDICTION AND PROCEDURAL HISTORY

1. On November 2, 1989, Northern States Power Company ("NSP" or "the Company" or "the Utility") filed a petition with the Minnesota Public Utilities Commission ("Commission" or "PUC") under Minn. Stat. 216B.16 for an increase in electric rates of $120,782,000 (a 10.2 percent increase over current rates). The Company also filed a Petition for Interim Rates in the amount of $90,845,000 (a 7.70 percent increase).

2. On November 13, 1989, the Company made a supplementary filing containing information which was inadvertently omitted from the original filing.

3. On November 29, 1989, the Commission accepted the Company's filing and suspended the proposed rates until the Commission determined the reasonableness of the proposed rates or the expiration of the ten-month statutory period (whichever comes first) under Minn. Stat. 216B.16, subdivision 2.

4. On December 29, 1989, the PUC issued an Order setting interim rates in this matter, which order authorized the Company to collect $81,542,000 in additional annual revenues in the form of a 6.91 percent surcharge to retail rate schedules as interim rates, beginning with bills for service rendered on and after January 1, 1990. NSP is collecting interim rates subject to full or partial refund if the interim rates are in excess of the final rates determined by the Commission.

5. On November 29, 1989, the PUC issued a Notice and Order for Hearing directing that a contested case hearing be convened to determine the reasonableness of the rate changes proposed by NSP.

6. On December 21, 1989, a prehearing conference was held before the Administrative Law Judge in the Public Utilities Commission's Small Hearing Room, 7th Floor, American Center Building, St. Paul, Minnesota. Petitions to Intervene were filed by and granted to:

1) Hubert H. Humphrey III, Minnesota Attorney General (OAG);

2) Champion International Corporation (Champion);

3) Union Carbide Corporation (UCC);

4) Metalcasters of Minnesota;

5) District Energy of St. Paul, Inc. (D

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6) Minnesota Senior Federation (Seniors);

7) North American Water Office (NAWO); and

8) the Minnesota Department of Public Service (DPS).

7. On December 29, 1989, the Administrative Law Judge issued a Prehearing Order establishing the hearing schedule and procedural guidelines governing the conduct of the case. On February 22, 1990, the Administrative Law Judge issued a Second Prehearing Order modifying the December 29, 1989, Prehearing Order and granting additional Petitions to Intervene to:

9) Minnesota Public Interest Research Group (MPIRG);

10) Minnegasco;

11) North Star Steel (North Star);

12) Minnesota Engergy Consumers (MEC);

13) Minnesota Retail Merchants Association;

14) St. Paul Area Chamber of Commerce (Chamber);

15) Suburban Rate Authority (SRA); and

16) City of St. Paul, et al. (City of St. Paul, St. Paul Board of Water Commissioners and Municipal Pumpers Association).

8. MPIRG did not appear at the hearings, sponsored no witnesses and filed no briefs.

Minnegasco and DESP withdrew as parties during the course of the evidentiary hearing. Their intervention in the case was prompted by NSP's proposal for a "Competitive Service Rider" in its intially-filed rate design. The affected parties (NSP, DESP and Minnegasco) agreed that Laws 1990, Ch. 370, 3 (to be codified as Minn. Stat. 216B.162, Competitive Rates for Electric Utilities), new legislation effective March 30, 1990, has obviated the need for litigating the Company's Competitive Service Rider in this rate case. NSP has withdrawn that rate proposal and the two Intervenors (who provide alternative sources of energy that compete with NSP) moved for dismissal of their Petitions to Intervene. Their motion was granted on April 11, 1990.

SUMMARY OF THE PUBLIC TESTIMONY AND WRITTEN COMMENTS OF

RATEPAYERS

9. Forty-six members of the ratepaying public testified at the public hearings. These speakers were evenly divided between individuals stating their own (or the groups' they represented) concerns and the comments and questioning of NSP officials and representatives by persons affiliated with four interest groups - Minnesota ACORN (Association of Community Organizations for Reform Now) in St. Paul, the regional Senior Federations in Winona and Mankato, the NSP Retirees Club of Local 160, International Brotherhood of Electric Workers (IBEW) and Local 160 itself. In addition, several commentators in Mankato are members of Mankato Citizens Concerned with Preserving Environmental Quality (MCCPEQ) who presented their concerns as individuals because the group's board had not yet met to endorse their remarks.

10. The plurality of individual commentators testified that NSP's proposal to cut the amount of the Conservation Rate Break (CRB) in the customer charge to customers who consume low levels of energy would result in unduly high percentage increases in monthly bills. Speakers representing ACORN and the Seniors groups also emphasized that central point.

The Senior Federation group in Winona presented the Administrative Law Judge with a petition signed by 58 Dodge County residents opposed to the rate increase proposal and, in prepared comments at both Winona and Mankato, presented a spread sheet alleging that while NSP claims it is asking only a 10.2 percent increase for residential customers, a customer who uses      kilowatt hours per month will have their charges raised      percent. The sheet alleged that a customer using 50 kilowatt hours will see a 46.8 percent higher bill, and continued the comparison in 50-kilowatt-hour increments to 400 kilowatt hours (a 12.7 percent increase). The Seniors contend that a customer would have to use 1,000 kilowatt hours per month in order to attain "only" a 10.2 percent billing increase. The Seniors speakers also argue that NSP wants Minnesota ratepayers to pay $20 million to "tear down" the Pathfinder Nuclear Plant in South Dakota, a plant from which Minnesota residents "never received electric power".

11. The ACORN speakers also focused on their individual situations, complaining that their electric bills were simply too high for their low, fixed level of income. Some of the ACORN speakers suggested a cap on utility bills for qualifying seniors and disabled persons, including using the Illinois program (which caps utility bills at 12 percent of net monthly income for qualified individuals) as a model. During the written comment period, the Administrative Law Judge received a petition signed by 229 ACORN supporters in Hennepin and Ramsey Counties, which petition reads: "Stop Utility Rate Increases!! With a contribution and a signature, I support ACORN's campaign to fight the $120 million rate hike proposed by NSP (Northern States Power)."

12. The NSP Retirees Club of Local 160, IBEW, is against the

rate increase. In written comments, the Club urges an examination of executive compensation levels, particularly liberal pension benefits, the rehiring as consultants (for exorbitant fees) of persons who recently took early retirement, the high number of lobbyists employed by the Company, and the alleged squandering of water resources by NSP. The Retirees Club also cautions against using ratepayers' revenues to build a plant to burn PCBs and the alleged Company practice of selling energy on the bulk power market it claims it has not produced due to consumer conservation efforts, but produced anyway.

13. Local 160 of the IBEW, representing the active members of the Local who work for NSP, filed a written comment supporting the rate increase proposal and claiming that NSP and the union have formed a partnership to cut costs and save energy. Their business agent noted that the Local and its NSP Retirees Club are two separate entities who share the same business address.

14. Several public witnesses asked NSP officials whether Minnesota ratepayers were still paying for the cancelled Tyrone nuclear facility in Wisconsin. The answer was no, not since 1987. One Dilworth commentator asked about a one-time refund to the ratepayers of the excess Federal taxes collected on a prepaid basis, taxed at a 46 percent corporate level, which turned out to be over-collected when the 1986 Tax Reform Act lowered the Federal corporate tax rate to 34 percent. Another complained that NSP failed to provide an adequate level of power in his neighborhood for several months after several neighbors put in central air conditioning.

15. One St. Cloud witness urges elimination of the customer charge portion of NSP's rates and using a flat rate based upon energy consumption. Anther St. Cloud commentator praised NSP for helping his company keep its energy costs low by managing its load and purchasing energy-efficient fixtures. Anther witness asked whether Minnesota was proposing that PUC members sit on utility companies' boards in Minnesota and participate in management duties such as collective bargaining, as had been proposed in the Wisconsin legislature. The witness was opposed to any such plans.

16. Two commentators expressed concerns relating to underground power cables - one wondered how soon all such cables in Coon Rapids would be build, and a Minneapolis witness (who resides in New Brighton) complained that he was being charged for an underground cable when the power pole to which it was connected stood in his back yard and he had no wish that the cable be buried. An NSP spokesperson explained that since the customer's house was newly constructed, an underground cable was required by city ordinance.

17. Witnesses for local chambers of commerce and economic development agencies appeared on NSP's behalf in St. Cloud, St. Paul (the Deputy Commissioner of the State Department of Trade and Economic Development), Minneapolis, Winona and Mankato. The witnesses praised NSP for its economic development efforts and commitment, particularly in the area of business retention, and cited the Company's good corporate citizenship. The Mankato

economic development witness specifically endorsed the Company's rate increase. Officials of two large employers (and business electric customers) in Mankato also testified that NSP had fair rates and helpful, courteous, professional employees.

18. Several Twin Cities Metro Area witnesses testified that the presence of a Conservation Rate Break in the customer charge caused them to conserve energy. Whenever they do not qualify for the Break, they make an extra effort to save energy the following month.

19. Several commentators suggested that interim rate increases should be eliminated and/or that refunds from interim rates be paid in cash, rather than as credits on bills. The Company replied to the latter suggestion by pointing out that it would be too expensive to print and mail a million checks.

20. Several people commented that they chose an apartment-dwelling lifestyle in order to conserve energy and keep down energy expenses. One such customer suggested that to cut the CRB now would amount to illegal discrimination against him for having chosen such a lifestyle and for being in an economic bracket that made home ownership unaffordable.

21. Much of the Mankato testimony focused on the nearby Wilmarth plant and its use of Refuse-Derived Fuel (RDF) instead of coal. The issues involve the toxicity of the smoke and fumes from burning of the RDF, disposal of the toxic ash residue, whether electric ratepayers should pay the extra costs involved in using this less-efficient fuel (or whether those costs should be included in refuse disposal rates) and whether the energy produced at the plant should be billed to customers on a costing model assuming it is baseload, rather than peaking plant-type energy.

Public witnesses argued that the Company charges for the energy as if it came from an energy-expensive "peaker"-type plant, whereas the Company, since converting the plant to RDF, operates it around the clock for many more days at a time. Therefore, the energy price should be lower, as if from a baseload plant. The witnesses also charged the Company with using the plant simply to provide a service for getting rid of Twin City Metropolitan Area-garbage without regard to financial or environmental costs.

22. Several witnesses advocated granting NSP no greater rate increases or return on equity that the annual rise in the Consumer Price Index (CPI).

23. At the St. Paul hearing, an NSP executive responded to the consumer concerns raised in public testimony by presiding over a discussion in which the Company emphasized that many of the problems had solutions in the form of assistance programs which NSP endeavors to bring to the attention of potential beneficiaries. The executive emphasized that the Utility cannot help if customers do not bring their problems to NSP's attention.

24. Neil W. Hamilton, Trustees Professor of Regulatory Policy at the William Mitchell College of Law, filed a written comment implying that he favors the use of incentive rewards, such as a

boost in allowed return on equity, to encourage utilities to exercise efforts toward low-cost production.

25. Written comments were filed by persons who allege they qualify for the CRB even though they live in houses, so that not all who receive the Break are apartment dwellers (as the Company implies in its literature).

26. The City of Morgan, Minnesota, through its City Clerk, filed a letter protesting NSP's decision to close its Morgan office and transfer its functions to Bird Island, 23 miles (and a dangerous wintertime bridge crossing) away. The City contends that NSP's decision makes lower service quality inevitable in the Morgan area.

27. A written comment was filed from a Louisiana resident alleging that the uranium enrichment plant NSP is considering investing in (as part of a consortium - the Graystone Project) will be utilizing methods that are tehnologically obsolete.

RATE OF RETURN AND CAPITAL STRUCTURE

28. In its November 2, 1989, filing, NSP requested an overall rate of return of 10.20%. NSP based its proposed rate of return on a capital structure consisting of 39.09% long-term debt with a cost of 8.48%, 1.31% short-term debt with a cost rate of 7.68%, 9.50% preferred stock with a cost rate of 5.90%, and 47.03% common equity with a cost rate of 13.25%. NSP also proposed that its capital structure include 3.07% for Tax Benefit Transfer Leases contributed to the capital structure by the shareholders at no cost.

29. Five Intervenors, the Department of Public Service, the Office of the Attorney General, North Star Steel, the Minnesota Senior Federation and Minnesota Energy Consumers, filed rate of return testimony in opposition to that filed by Northern States Power Company. The chief dispute between NSP and the Intervenors in this area lies in the contrast between the 13.25% return on equity (ROE) recommended by NSP and the following ROEs recommended by witnesses for the Intervenors:

| Intervenor Witness | Recommendation |
| --- | --- |
| Thompson - DPS | 11.75% |
| Dahlen - MEC | 11.75% |
| Zapp - Seniors | 11.50% |
| Marcus - OAG | 11.40% |
| Smith - North Star | 10.50% |

30. There is agreement between NSP and the Intervenors that the test year cost of debt is 7.24% and the cost of preferred equity is 5.90%. The disputes regarding the appropriate cost of equity and capital structure are discussed below.

31. Minn. Stat. 216B.16, subd. 6, requires an allowed rate of return that is "fair and reasonable". The Supreme Court of the United States defined the reasonableness of a utility's

return in Bluefield Waterworks and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923). The Court concluded that a utility did not have rights to profits such as those realized in a speculative venture, but stated that the utility's return:

> ". . . Should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."

In Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944), the Court reiterated the Bluefield principles and discussed the necessity of properly balancing ratepayer and investor interests in order to fix just and reasonable rates. The Hope Court affirmed the investor requirement for sufficient revenue to cover operating expenses, including services on debt and dividends on stock. By that standard, the investor's return should not only be sufficient to assure confidence in the utility's ability to maintain credit and attract capital, but the return should also be similar to returns on investments in other businesses having corresponding risk.

32. The cost of equity cannot be determined with precision or derived from a formula, but must be derived through the exercise of reasonable judgment after a full review of all evidence and testimony. Northwestern Bell Tel. Co. v. State, 216 N.W.2d 841, 857 (Minn. 1974); Hibbing Taconite Co. v. Minnesota Public Service Commission, 302 N.W.2d 5, 11 (Minn. 1980).

33. The cost of common equity is the return investors require on an investment in the common stock of a company, not what return the company will probably earn or actually earn. Estimating the cost of common equity requires professional judgment and cannot be done mechanically. This estimating process requires applying acceptable financial valuation methods and taking into account the circumstances of the company, industry and capital market conditions.

34. The cost of common equity for a company whose stock is actively traded is best estimated from available stock market data. The Discounted Cash Flow (DCF) method is a market-oriented opportunity cost approach which views the relationship between the cost of equity, investors' income expectations and market price in a theoretically sound and systematic manner. This method has been relied upon by the Commission in nearly every case since 1978.

35. The theoretical foundation for the DCF method is that shareholders derive their required return from an investment in two forms: yearly dividend and growth in dividends. The DCF method estimates the cost of common equity by combining an appropriate dividend yield with a future growth rate expected by investors.

36. NSP's financial position is strong relative to that of other utilities. Investors distinguish between utilities which are subject to nuclear construction risks and utilities which are not faced with such risks. NSP does not have any nuclear plants under construction. Since NSP has common equity stock which is actively traded on the New York Stock Exchange, the DCF method of analysis estimating the cost of common equity by combining an appropriate dividend yield with a future growth rate expected by investors is appropriate.

37. Since NSP common equity stock is traded in the market, making its price, dividends and past performance directly observable, primary weight should be given to a direct DCF analysis of NSP. Evidence regarding companies whose risks are comparable should be used as a check on the DCF results for NSP. The PUC adopted that approach in its order in the 1986 NSP rate case. The dividend yield is the dividend rate divided by the stock's price. The major inquiry in the dividend yield analysis is the selection of the appropriate yield.

38. The selection of the appropriate dividend yield period is one of judgment but should be sufficiently long to average out temporary market aberrations and reasonably reflect the period of time during which the new rates will be in effect.

39. The dividend yield must reflect current conditions as well as investor expectations for the future regulatory period. The growth rate is the rate at which investors expect dividends to grow through their investment time horizon.

40. In theory, the short-term period more fully reflects the longer-term expectation of investors in the current regulatory period. In an effort to estimate fairly the current dividend yield, DPS witness, Dr. Thompson,.used an average of the two-year annual yield (6.54%), the one-year annual yield (6.36%), the most recent quarterly data (6.02%) and the 20-day yield (5.94%). The resulting average is 6.22%. Dr. Marcus, the OAG witness, used a 12-month period to calculate the dividend yield, which he found to be 6.2%.

41. The PUC has consistently found a 12-month period to be an appropriate time parameter for determining dividend yield. Northern States Power Company, docket E-002/GR-87-670 (12 months averaged with 3 months); Northern States Power Company, docket numbers G-002/GR-86-160, G-002/M-86-165; Central Telephone Company, docket P-405/GR-83-300 (1984) (four quarters).

42. Dr. Marcus of the OAG and Dr. Zapp of the Seniors argue that financial theory requires that the unadjusted dividend yield figure be adjusted to reflect higher dividends which will be received in the first year. Each adjusted their dividend yield figures by multiplying them by one-half the expected growth rate. In the case of Dr. Marcus, that calculation produced a 6.4% dividend yield figure. Dr. Zapp's calculations on behalf of the Seniors produced a dividend yield figure of 6.3% after multiplying his dividend yield figure by half the expected growth rate.

43. Neither NSP rate of return witness, Chief Financial

Officer James Doudiet or Dr. Charles Benore, advocated use of the DCF methodology to determine an appropriate return on equity allowance. Mr. Doudiet used the risk-premium method in arriving at his recommendation, and Charles Benore used a Yield Spread Discounted Cash Flow (YSDCF) approach. As noted in subsequent Findings, neither the risk-premium approach or the newly-advanced YSDCF methodology is appropriate for adoption in this proceeding.

44. The appropriate dividend yield for NSP is 6.5%.

45. The most common methods for estimating the growth component using the DCF method are extrapolations from past trends in earnings per share, dividends per share and book value per share, growth in retained earnings and analysts' growth estimates. Since returns on equity and pay-out ratios are not constant, historical growth rates of earnings, dividends and book equity are unequal.

46. Due to the Company's earnings growth between 1980 and 1983, NSP has had a high rate of growth over the last ten years. NSP's rate of return on common equity increased significantly from 11.7% in 1980 to 17.1% in 1983. Thereafter, the Company's return on equity declined each year and earnings growth since 1983 has averaged just under 2% per year. In the 1986 rate case, the PUC agreed that NSP's growth trends should be accorded little weight because of the high growth in the early 1980s. See NSP dockets E-002/GR-85-108 at 41 and E-002/GR-85-558 at 68.

47. Rational investors will rely predominantly on the dividend growth for the last two years because this growth was maintained while NSP earned the lowest return on equity in five years. NSP's average dividend growth for the past two years is 5%.

48. In calculating the growth component, DPS witness Thompson examined the five and ten-year growth rates in book value, dividends and earnings per share, as well as log linear growth rates. Dr. Thompson maintains that for rate of return considerations, the past five to ten years is sufficiently long to dampen the cyclical variations that occur because of short-term market conditions. In the case of NSP, growth in book value and dividends per share are clearly less variable than growth in earnings. Thompson determined that a fair and reasonable estimate for the expected growth rate for NSP is the range of 4% to 7%. This estimate of the long-term growth rate is reasonable not only because the value line and analysts' projections indicate that growth and earnings will be smaller, but because it also reflects the growth in dividends and book value along with investors' reasonable expectations. Thompson used the mid-point of his growth range, 5.5%, to estimate growth.

49. Relying on NSP's average growth for the past two years (5%) and estimates of future growth for NSP by forecasting services, as well as estimating growth from retained earnings by projecting the growth in book equity attributable to NSP's retention of earnings (derived by multiplying NSP's prospective rate of return on equity by the proportion of earnings NSP is expected to retain), Dr. Marcus for the OAG predicted a growth

figure for NSP during the test year of 5%.

50. MEC witness Derrick Dahlen recommends an 11.75% ROE, which is the Federal Energy Regulatory Commission's (FERC) benchmark rate of return. Dahlen advocates adoption of the FERC benchmark because it satisfies the criteria adopted by the Commission for return on equity. FERC establishes its benchmark rate by using a discounted cash flow method, it reflects recent financial markets and is established by a process that is more thorough (includes more companies) than any presented in an individual rate case.

51. MEC argues that the 11.75% rate of return satisfies the PUC's criteria for a fair rate of return in part because NSP has a percentage of common equity high enough to maintain a AA bond rating and therefore is a less risky investment than most other utilities. Therefore, the Company's required return on equity should be lower than the FERC generic rate because NSP is less risky than other electric utilities.

52. It is appropriate to adopt a growth rate for the test year for Northern States Power Company in this proceeding of 5.3%.

53. NSP witnesses Doudiet and Benore rejected use of a DCF model to determine return on equity for NSP. Mr. Benore provided an extensive study covering two economic cycles for the relationship between NSP stock prices and Long-Term U. S. Government (LTUSG) bonds, which study purports to show that the current market inefficiently depresses the yield component of the standard DCF model, causing it to understate NSP's true cost of capital at this point in the economic cycle. The inefficiently high stock price has been caused in part by the defensive buying of electric utility stock since October 1989, which trend lifted prices to levels that cannot be sustained in the long run.

54. NSP argues that the time periods used by DCF witnesses for the Intervenors were too short because they included data for months when yields were depressed because of market inefficiencies. It emphasizes that since the rate case was filed, NSP's stock prices climbed over $40 and then moved rapidly down to under $34, from which is has recovered slightly. This volatility in NSP's stock shows that a longer term analysis is required to derive the yield component than would be the case in a stable market. The Company argues that a 12-month average is not sufficient to eliminate market volatility and inefficiency.

55. In estimating the DCF growth factor, the Company argues that since the Commission must attempt to determine the rate at which investors expect dividends to grow for the indefinite future, an exercise that is difficult and perhaps impossible to determine empirically, expert witnesses using DCF methodology are forced to offer opinions of what they think investors expect dividends to be in the future by reviewing past growth rates, dividends and earnings, and on what other experts publish in the way of growth projection. The basic data used by the experts includes a very wide array of growth rates. Using the same essential data, which each weighs and averages in different combinations to develop different ranges and recommendations, DCF methodology advocates arrive at varying estimates of future

growth.

56. NSP argues that if standard DCF methodology is employed, the results (which indicate a cost of equity in the range of 11.4% to 11.9%) must be adjusted for market efficiency and flotation costs.

57. Flotation costs are a relevant consideration in determining the yield on stocks or bonds during periods when new stock issues are offered to the public. No stock issues are anticipated by NSP during the proposed test year.

58. NSP proposes allowing for flotation costs by adding 30 to 44 basis points to the DCF measurement for the cost of equity for NSP.

59. NSP witness Charles Benore examined the assumptions which form the foundation for the DCF method and determined that the assumption that the market efficiently prices the stock has not been valid for NSP for several months. Benore argues that the Company's stock was overpriced relative to LTUSG bonds, a phenomenon typically occurring late in an economic cycle. Also, defensive buying of utility stocks raised the prices above sustainable levels. As a result, mechanical application of the standard DCF method produces a yield component that is too low by 74 basis points, according to Benore. Based on data covering two economic cycles, NSP's yield factor should be about 118 basis points below the LTUSG bond yield.

60. Mr. Benore's YSDCF methodology provided the primary basis for his recommended return on equity, which is 13.00%.

61. The risk premium method attempts to measure the size of the additional return required for stocks above bond yields to compensate investors for the greater risk of common stock. NSP argues that it provides a useful check of the accuracy of DCF results as well as an independent measure of the cost of equity.

62. James Doudiet, NSP's Chief Financial Officer, performed a risk premium analysis for NSP common stock and found that the stock return generally exceeds bond yields by about 3.7%. Because financial markets have become volatile, it is important to use data derived from an extended time period. Doudiet's risk premium study indicated a cost of equity for NSP of 13.4%.

63. The risk premium method is based on the assumption that common equity is more risky than debt and that the rate of return for equity must be proportionally higher than the interest rate on bonds. A risk premium analysis can be developed by taking the "risk free rate" (usually treasury bills or the return on long-term government bonds) and adding it to a "risk premium" based on differences in returns over a selected period of time.

64. A significant problem with risk premium methodology is the number of assumptions which must be made to arrive at the rate of return. The more assumptions one uses, the greater the uncertainty. This situation leads to greater subjectivity in using the risk premium methodology than in using the DCF model.

65. Mr. Doudiet's examination of NSP returns during the period of 1971 - 1988 is an examination of a cycle wherein enormous volatility in returns occurred. Using the data for the period from 1974 - 1988, for example, would produce an expected return of 16.39%.

66. Doudiet argues that rate regulation does not acknowledge performance. In order to link performance with the rate of return on equity, Doudiet created a "report card" designed to associate the grade which NSP has assigned to itself to the return on equity which NSP wants the Commission to award in this proceeding. The grading system for rate of return is part of an overall grading system advanced in this case by NSP.

67. Doudiet characterizes the grading system regarding return on equity as a "logic check". He developed his grading chart by starting with the FERC benchmark rate (then 12.04%, 11.75% at the time of the hearing) and giving FERC a "C" average "because FERC does not take performance into account". Then, reviewing state commission orders issued in 1989 nationwide, Doudiet averaged rates of return and determined that this average (12.9% - 13.04%) could "also be viewed as appropriate for 'C' performance on the theory that even if other commissions do take performance into account, it averages out". He assigns the top of the range (13.04%) as "B" performance. With those two points established, Doudiet assigned a "D" to NSP's current return (11.70%) and "A" to "A-" to NSP's proposed rate of return on equity of 13.25%.

68. The above analysis by Mr. Doudiet ignores the fact that better management and hence better performance reduces the financial risk in investing in a particular utility company and also reduces the expected returns of investors in such companies. Moreover, better managed utilities have a higher probability of achieving or exceeding their allowed rates of return, so NSP, which no party to the evidentiary hearing alleges is poorly managed, should not require such a high rate of authorized return in order to attract investors.

69. It is logical that poorer performing utilities will have higher capital costs because their rate of return on equity is necessarily higher to reflect the requirements of the capital markets. Conversely, better performing utilities can enter the capital market with a lower rate of return.

70. Mr. Doudiet's grading system bears no rational relationship to NSP's required rate of return on equity. NSP is a financially sound company, successful in attracting investors and obtaining capital. There is no market evidence which would indicate that the Company's current 11.7% return on common equity is too low.

71. Doudiet's grading system is contradicted by the principles of traditional rate of return analysis. Nothing in the record lends support to NSP's proposition that rate of return analysis should be so radically revised. To make such a drastic revision would only accomplish NSP's goal of achieving an allowed rate of

return it desires, but which is not necessarily warranted based on traditional market trend analysis. 72. NSP witness Benore reviewed old rate of return decisions from other jurisdictions and compared the results with current DCF analyses, which analyses resulted in returns on equity in the range of 10.50% to 11.75%. Benore's "yield spread discounted cash flow" (YSDCF) model is not considered in the finance literature, is Benore's own creation, and this case is the first proceeding in which the method has been presented in support of rate of return testimony.

73. Upon close analysis, Benore's YSDCF model appears to be a variant of risk premium analysis. The model is based on the view that the stock market prices need not reflect the stock's true value, and that the degree of price/yield inefficiency can be measured at any point in time.

74. NSP's common stock is traded actively by a large number of informed investors, including institutional investors. These investors form their opinions based on their own studies, as well as on the basis of investment reports prepared by experienced analysts. Nothwithstanding that situation, Benore is arguing that NSP's stock prices do not represent rational evaluations by informed investors, and that such "inefficiencies" last over a long period of time.

75. Benore increased his proposed rate of return by allowing for "flotation costs" and "increased risk". No new sales of common stock are planned by NSP at least through 1993. Compensation at this time for past sales is contrary to rate making practices - if flotation costs are to be an issue at all, they should relate to the current rate case and not past periods.

76. The DPS argues that when stripped of the "yield spread" (the adjustment for stock that NSP claims is not over-valued and a spread that does not exist), the "flotation cost" adjustment for non-existent stock sales, and "risk" which is unproven, Benore's analysis becomes a DCF model. Based on yield and growth, Benore's testimony supports a growth range of 5.00% - 5.80% and a yield of 6.19%, creating a range of return on equity of 11.19% - 11.99%.

77. The appropriate return on equity for Northern States Power Company during the test year is 11.8%.

78. With respect to capital structure, Dr. Caroline Smith of North Star and Dr. Kenneth Zapp of the Seniors advocated a common equity ratio of 45.00% and 45.30%, respectively, as opposed to the 47.03% advanced in this proceeding by NSP and accepted by the other intervenors who presented testimony on rate of return.

79. The common equity ratio of 47.03% reflects NSP's actual capital structure, on the assumption that the tax benefit transfer lease monies are properly included in the capital structure as no-cost debt.

80. North Star recommends a common stock ratio of 45%, after removing tax benefit transfer leases (TBTs) from the capital structure. North Star argues that the Company has offered no persuasive evidence that the benefits of a common equity ratio in excess of 45% outweigh the costs to the ratepayers of such a ratio. Dr. Smith points out that ratepayers pay for a high common equity ratio through a higher overall rate of return requirement.

81. On behalf of the Seniors, Dr. Zapp maintains that the goal in capital structure policy should be the minimalization of the weighted average or overall cost of capital. Dr. Zapp is not persuaded that NSP has presented evidence that compels the Company to increase its equity ratio from the 1988 rate case (during which the Company voluntarily entered a stipulation calling for a 45.3% equity ratio).

82. Given the fact that the Company has been able to maintain an AA rating from Standard & Poor's since the time of the 1988 rate case, when it stipulated to an equity ration of 45.3%, and that economic conditions between 1988 and 1990 are similar, Dr. Zapp is unpersuaded that the evidence compels a conclusion that the Company should be allowed to increase its equity ratio from that stipulated to in 1988.

83. DPS witness Thompson testified that NSP's actual capital structure was reasonable in light of equity ratios of comparable companies. OAG witness Dr. Marcus found that NSP's equity ratio was similar to other AA utilities, and he testified that the Company's proposed capital structure was reasonable, proper and in the public interest.

84. It is appropriate to include tax benefit transfer (TBT) lease monies in the capital structure as no-cost debt.

85. An appropriate capital structure for NSP for the 1990 test year includes a common equity ratio of 47.03%, including tax benefit transfer lease monies in the capital structure as no-cost debt.

Cost of Capital Summary

86. NSP's appropriate overall cost of capital is 9.52%, compiled as follows:

| | Percentage | Cost | Weighted Average |
|---|---|---|---|
| Long-term Debt | 39.09 | 8.48 | 3.31 |
| Short-term Debt | 1.31 | 7.68 | 0.10 |
| TBTs | 3.07 | 0.00 | 0.00 |
| Preferred Equity | 9.50 | 5.90 | 0.56 |
| Common Equity | 47.03 | 11.80 | 5.55 |
| Total | 100.00 | | 9.52 |

Discussion

NSP has not sustained its burden of establishing that its requested return on equity of 13.25% is just and reasonable. The methodologies proposed for determining the rate of return on equity, one of which yields a recommendation of 13% and the other 13.4% (as its final request, the Company chose a 13.25% ROE) do not persuade the Administrative Law Judge that a departure from traditional DCF methodology is appropriate, and, as the Company admits, traditional DCF methodology leaves NSP with a recommended return on equity lying between 11.4% and 11.99%.
The Commission's obligation to set a fair authorized return does not include a guarantee that the authorized return will be earned. A utility is only to be granted the opportunity to earn as much as its allowed return. It is not an objective of regulation to assure a utility a specific rate of return for its investors or to guarantee such a rate of return. The Public Utilities Commission is only obligated to set a reasonable authorized rate of return which provides the Company with the opportunity to earn at that level. A fair rate of return for which a utility should be authorized is a rate no greater than its weighted average cost of capital which, if earned, will permit the utility to recover the cost of fixed securities and also the cost of common equity.

The authorized rate of return must be commensurate with the risks of the enterprise. No purpose is served by allowing a return which is higher than required by NSP's investors. Authorizing a return in excess of that required by the investors confers windfall gains on investors, while imposing unnecessary burdens on ratepayers. It is appropriate for the Commission to ensure that the rate of return for equity established for NSP in this proceeding is no greater than the amount necessary to protect investor interests.

The required rate of return is that which is necessary for investors to buy or hold a security. An investor's rate of return should reflect the total evaluation of risks the investor is willing to assume for an expected return on investment. The greater the risk in any investment, the greater must be the expected return to compensate for the risk.

An important starting point for an assessment of NSP's prospective risk is an overview of its financial condition. Based on the Company's financial reports, NSP is in sound financial condition. NSP's bonds are rated AA by both Moody's and Standard & Poor's. In recent years NSP's annual earnings rate has exceeded the Company's cost of capital and its authorized rate of return.

During the second half of 1989, NSP's investors priced the Company's common stock at more than 50% above book value. This indicates the investors believe that NSP's earnings are more than adequate.

Translating NSP's risk into a just and reasonable return on equity requires an analysis incorporating both NSP's current yield and expected growth as well as an analysis of companies whose risk is comparable to that of NSP. The DCF method is generally considered the most basic and fair approach for regulatory purposes in determining the cost of common equity.

The Minnesota Public Utilities Commission has consistently utilized the DCF method in making its determinations of the appropriate rates of return for Minnesota utilities. DCF methodology provides objective information concerning the cost of common equity capital during an expected regulatory period.

Using the DCF technique, the cost of equity is derived by calculating the current dividend yield and the expected growth in dividends. The dividend yield must reflect current conditions as well as investor expectations for the future regulatory period. The growth rate is the rate at which investors expect dividends to grow through their investment time horizon.
It is useful to compare comparable companies, whose risks for investors are similar to those of NSP's, to verify the reasonableness of the results obtained directly for NSP. To confirm his rate of return analysis, Dr. Thompson of the DPS performed a DCF analysis on a comparable group of utilities. A similar approach was taken by Dr. Marcus for the OAG. Several criteria were used by these witnesses to establish comparability. For instance, of the 95 electric utilities whose stocks are listed on the New York Stock Exchange, the utilities which are subject to nuclear construction risks were removed from the analysis. NSP has no such risks, and is among the 30 largest companies ranked by revenue size, another classification used to determine comparable group. It is reasonable to impose a size constraint on the comparison group to make the comparable group manageable yet statistically meaningful, and to make it more homogeneous.

Bond ratings should not be used as a screening device because such ratings are designed to measure risk to bond holders and do not assess investment risk to common equity shareholders.

NSP recommends a procedure which involves the PUC choosing among recommendations based not upon the merits and analysis of experts applying DCF methodology but rather upon NSP's "performance". Such a methodology is flawed because it would steer the Commission away from basing its return on equity determination upon the Company's financial needs.

Under regulation, poorer performing companies have higher capital costs and these high capital costs are reflected in higher rates of return. Conversely, better performing utilities can successfully enter the capital markets with a lower rate of return. These economic facts exist independent of regulation as well. However, under rate regulation, better performing companies are entitled to a lower rate of return than poor performers.

Basing return on equity on performance has anomalous effects. If poor performing utilities receive rates of return below what is necessary, there could be a downward spiral of actual rate of return.  In order to meet their obligation to ensure continuous services to ratepayers, less efficient utilities are granted an ROE sufficient to meet their needs.  Conversely, a rate of return higher than sufficient to meet a utility's capital needs and provide a reasonable rate of return to investors results only in higher rates and more profit.

The Administrative Law Judge agrees with the Intervenors who advocate that the goal of regulation in the area of rate of return is met when rates are set at the lowest level consistent with allowing the firm the opportunity to earn a return sufficient to meet the above-noted Bluefield and Hope standards. Such a conclusion is consistent with Hibbing Taconite Co. v. Minnesota Public Utilities Commission, 302 N.W.2d 5 (Minn. 1980). A close reading of that case shows that the Supreme Court overturned the Commission's method of focusing on the witness with the lowest return, not the goal of seeking the lowest sufficient return.  NSP's return on equity should not be adjusted because of NSP's performance as an efficient business.  The DCF methodology provides an accurate reflection of the risk in purchasing NSP stock.

NSP has requested the Commission, as a "logic check", to compare the rate of return appropriate for the Company under DCF methodology to ROEs granted to other companies during 1989.  Such a comparison would be misplaced.  No Commission decision has ever based ROE on the findings of other states.  Rate of return decisions are unique to the particular company, based upon the capital needs for that company.
It is significant that return on equity decisions in 1989 were based upon different, older data than will be used in this case. There is no guarantee that the decisions reached in 1989 would have had the same results regarding ROE in 1990.  Other states may have different substantive rules.  Investors know the differences in rates may be offset by positive regulatory features, and Minnesota has two such features: interim rates and a forecasted test year.

In order for the Commission decisions selected by Doudiet to be issued in 1989, the hearings would have taken place in 1987 or 1988, as would the analyses supporting rate of return testimony in those proceedings.  As noted by the DPS, yields have steadily declined in the last two years, thus the results of a 1987 analysis are probably immaterial to the same analysis performed today.  Some of the decisions listed by Doudiet were the results of settlements between the parties.  Some were excluded from the list, and NSP was unable to explain the impact on its comparison if all had been included.  Finally, relating to the Company's grading scale, two of Mr. Doudiet's companies would receive a grade higher than A: Long Island Lighting Company (14.2%) and Illinois Power (14%).  The Long Island Lighting decision was a settlement, and the 14% awarded to Illinois Power reflected a risky company with imprudent costs associated with having its nuclear reactor disallowed from rate base, as well as 27.2% of imprudently incurred costs disallowed from rate base.

The risk premium analysis advanced by NSP witness Doudiet requires the existence of a mathematical relationship between the stock and bond markets.

As noted in the above Findings, the results of risk premium methodology are extremely volatile. They can vary based upon the holding period selected. Because of such problems, the PUC has consistently rejected risk premium analysis as a determinant of return on equity.

The Yield Spread Discounted Cash Flow (YSDCF) methodology advanced by NSP witness Benore in this proceeding differs from the DCF method in the calculation of the yield element. The YSDCF yield element is the calculated difference between the averaged yields on Long-Term United States Government Bonds (LTUSG) and the averaged yields on NSP stock. The yields for LTUSG bonds and NSP were averaged over the period 1974 - 1988. The difference between the two averaged yields (1.18%) is termed the yield spread. That spread is then subtracted from the current LTUSG yield of 8.12% to derive the YSDCF yield of 6.94%.

Benore calculated an unadjusted YSDCF figure for Return on Equity of 12.34% by adding the 6.94% yield to his growth figure of 5.40%. He then added a flotation cost adjustment and a risk adjustment to reach his recommended ROE of 13%. It is noted that the average yield for NSP common stock between 1974 and 1988 was 8.41%.

The YSDCF method rests on two assumptions: (1) that the stock market is inefficient and that it can remain inefficient for some time; and (2) that the degree of inefficiency can be estimated based on past averages. Benore believes that the stock market prices do not reflect the stock's true value and that NSP stock is currently over-valued.

NSP witness Doudiet's risk premium analysis seems to contradict the premise that there is an inefficiency between the stock and bond markets. Doudiet's analysis uses stock prices just as if they were fairly valued and did not adjust them for an inefficiency.

NSP's stock is actively traded on Wall Street and followed by a large number of investors. In addition, there is a great deal of information about the Company and its stock available to investors. An increasing proportion of market transactions are handled by large institutional investors, who rely on sophisticated analysis and are able to shift capital quickly from an over-valued to an under-valued segment of the market.

In order to validate Mr. Benore's premise that the current market inefficiency can be estimated, it must be shown that the differential between LTUSG yields and NSP yields is relatively constant over time. Such a relationship does not exist, in part because the two securities are distinct and subject to different risks. Benore characterizes the changes of the relationship of the yields between the two securities over time as being evidence of inefficiency; however, the Administrative Law Judge is persuaded that the changing proportions reflect investors' changing views as to the relative risks of the two investment vehicles over time.

There are dramatic differences between the relevant yield spreads for 1974 - 1980 and 1982 - 1988. Economic conditions during the two periods were greatly different. The yield spread for 1974 - 1980 is actually a negative figure (-0.15%), whereas for 1982 - 1988 it was +2.45%. Given the dramatic differences between yield spreads for the 1974 - 1980 and 1982 - 1988 cycles, there seems no justification for combining the two results and using the overall average as an estimate of a yield spread in connection with calculating a yield for NSP's stock during the test year.

For the reasons stated above, Mr. Benore's YSDCF model should not be relied upon in setting an appropriate return on equity for NSP. It is noted further that Mr. Benore also adjusted his recommendation to reflect "additional risks", as well as the adjustment he made for flotation costs discussed above. Benore identified three sources of risk: (1) bankruptcies and reduced dividends within the electric utility industry; (2) increased competition; and (3) effects of the Tax Reform Act. The Administrative Law Judge concludes that it is inappropriate to adjust return on equity for such factors in this case. Bankruptcies and reduced dividends have mainly affected nuclear construction industries, and NSP is not currently engaged in building a nuclear plant. Because of NSP's generally lower rates, it is not affected severely by competition. Finally, during calendar year 1990, the Tax Reform Act will not have a pronounced effect on NSP.

The yield component recommended by the Administrative Law Judge, 6.5%, represents an appropriate mid-point among the recommendations of expert witnesses who used DCF methodology in calculating an appropriate return on equity for NSP. The yield components recommended ranged from 6.0% (Dr. Smith for North Star) and 7.28% (Mr. Dahlen for MEC). The 6.5% recommendation for yield component matches that of DPS witness Thompson and is very close to that advanced by OAG witness Dr. Marcus. The estimates made by those two witnesses constitute deployment of "best evidence" in this case because they involve investors' actual expectations regarding NSP. This is so because market evidence permits a direct estimate of NSP's cost of common equity. Indirect estimates, based on analyses of comparable companies, should be deployed only as a check on the direct estimate. The growth rate of 5.3% recommended by the Administrative Law Judge strikes a balance between the 5.5% recommended by Thompson and the 5.0% recommended by Dr. Marcus. Regarding the common equity portion in NSP's capital structure, the actual proportion of 47.03% is recommended because NSP has proven that it is just and reasonable. The comparable groups' common equity ratios, as noted in the appendices to the testimonies of Dr. Thompson and Dr. Marcus, are comparable to those of NSP. It is appropriate to allow NSP its actual capital structure for regulatory purposes after making reference to norms based upon risk-comparable groups and industry averages to determine appropriate benchmarks. See DPS Ex. 152, Schedule 2, page 18 of 21. It is noted that the comparable group of AA-rated utilities analyzed for comparison purposes by Dr. Marcus for the OAG had a composite common equity ratio of 47.00%. It is therefore just and reasonable to allow NSP's actual common equity ratio of 47.03% for regulatory purposes during test year 1990. It is also appropriate for NSP to include in its capital structure, as no-cost debt, TBT lease monies. This conclusion is explored in greater detail in a subsequent discussion following Findings on the Tax Benefit Transfer Lease issue.

TEST YEAR

87. The appropriate test year for determining NSP's revenue deficiency is the 12-month period from January 1, 1990 to December 31, 1990, as filed by NSP. The use of a forecasted future test year is consistent with NSP's past practice and the Commission's past Orders. NSP's proposed test year is reliable for ratemaking purposes. It is appropriate to reject the proposals by the DPS and North Star that NSP should withdraw this general rate increase filing and refile on the basis of a historic test year.

BURDEN OF PROOF

88. Minn. Stat. 216B.16, subd. 4 (1988) places on the utility proposing a rate increase the burden of showing the reasonableness of its proposed rates. Under Minn. Stat. 216B.03, every rate made, demanded or received by any public utility " . . . shall be just and reasonable. . . . Any doubt as to the reasonableness should be resolved in favor of the consumer."

89. The DPS argues that the burden of proof in a general utility rate case is for the utility to demonstrate the reasonableness of proposed rate increases with evidence characterized as concrete, clear and convincing or persuasive. As the basis for this assertion, the DPS relies on PUC decisions in NSP's 1986 rate case and the Interstate Power Company decision in Docket E-001/GR-76-1876, wherein the Commission applied the "any doubt as to reasonableness" standard of Minn. Stat. 216B.03 to a record in which the utility asked the Commission to grant it a working capital allowance for a partially projected test year solely on the basis of historical working capital data. The Department maintains that the Commission, having held that in light of Minn. Stat. 216B.03, that the general "preponderance of the evidence" standard set forth at Minn. Rules pt. 1400.7300, subp. 5 do not apply to the determination of reasonableness of utility rates, should not apply that standard of proof in this case.

90. In response, NSP argues that the Department's analysis of burden of proof stops short of the relevant precedent. NSP notes that the Minnesota Court of Appeals and Minnesota Supreme Court both specifically addressed the appropriate quantum of proof needed to establish the reasonableness of a proposed rate change and reversed the Commission's Order. By implication, the

Commission's reliance on its earlier Order in Interstate was also overruled, NSP argues.

91. In In re Northern States Power Company, 402 N.W.2d 135 (Minn. App. 1987), the Court of Appeals rejected the Commission's analysis and stated (402 N.W.2d 139):

> We find . . . that the appropriate quantum of proof needed to establish the reasonableness of a proposed rate change is the same as in any other civil case -- a fair preponderance of the evidence."

On review by the Supreme Court, the determination on burden of proof by the Court of Appeals was affirmed. (In re Northern States Power Company, 416 N.W.2d 719 (Minn. 1987). The Supreme Court noted that the Commission had failed to contest the holding of the Court of Appeals and therefore it had become the law of the case. It was noted that the brief filed by the Commission before the Supreme Court indicated that the PUC would follow the ruling of the Court of Appeals - that the fair preponderance test would be utilitzed in ratemaking in future proceedings (416 N.W.2d at 722).

The Supreme Court went on to provide further explication of the fair preponderance standard as applied to fact-finding processes in utility rate cases. The Court noted that the weighing of evidence to be employed by the Commission differs from the weighing of evidence traditionally employed by a court (416 N.W.2d at 722):

> "In evaluating the validity of a rate increase application, the Commission should apply the classic burden of proof analysis employed in civil cases in determining whether the utility has established the amount of a claimed cost as a judicial fact. . . . But in the exercise of the statutorily imposed duty to determine whether the conclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts both in a quasi-judicial and a partially legislative capacity.

92. The suggestion of the DPS that the quantum of proof necessary to satisfy the burden of proving the reasonableness of a rate change is either the "clear and convincing" standard, or a standard approaching "beyond any reasonable doubt", is contrary to the above-noted Minnesota decisions and should be rejected. Moreover, at this stage of the proceeding, the Administrative Law Judge is acting in a quasi-judicial capacity. The Court of Appeals and Supreme Court have made it clear that the Judge's fact-finding function in a utility rate case is to determine whether the proponent of a given position has established sufficient facts to support the reasonableness of that position by a fair preponderance of the evidence. The question of whether the evidence thus established on the record results in "just and reasonable" rates is left to the judgment of the Commission.RATE BASE, OPERATING EXPENSE AND INCOME STATEMENT ISSUES

Pathfinder

93. In this proceeding, NSP has requested reimbursement for expenses associated with decommissioning its Pathfinder Atomic Power Plant in Sioux Falls, South Dakota.

94. On July 2, 1990, NSP filed Amendment #10 to its "NRC material license" for the Pathfinder plant. The Amendment, issued June 28, 1990, includes an authorization from the Nuclear Regulatory Commission (NRC) for "decommissioning of the Pathfinder Atomic Power Plant Fuel Handler Building and Reactor Building". NSP has asked the Administrative Law Judge to take official notice of the document. That request is DENIED because the time limitations imposed upon the Judge in this proceeding, which limitations result from a September 4, 1990, statutory deadline by which time the PUC must make its decision in this case, do not allow a period of time sufficient to allow the Intervenors to "contest the facts so noticed" while the case is before him. It is the prerogative of the Commission to give official notice to the document, so long as the parties have the opportunity to contest it, before reaching its decision. Minn. Stat. 14.60, subds. 2, 4, In the Matter of Northern States Power Company, 440 N.W.2d 138, at 141 (Minn. App. 1989).

95. NSP estimates that the decommissioning of the Pathfinder nuclear plant will cost approximately $15.7 million. Its proposal in this rate case is to include in test year operating expenses $2,729,000 as amortization of decommissioning costs associated with the nuclear portion of Pathfinder during the test year. In addition, the Company has included $3,412,000 in its net rate base (as working capital), a figure derived from subtracting accumulated deferred income taxes from the unamortized portion of the Pathfinder decommissioning investment ($5,632,000).

96. The Administrative Law Judge finds that NSP has failed to prove that its ratepayers should bear the cost of decommissioning the Pathfinder plant.

97. The question of whether or not NSP's proposed cost of $15.7 million to decommission the Pathfinder facility is reasonable is immaterial and need not be reached in this proceeding. Any costs associated with the decommissioning are not recoverable from ratepayers because NSP's ratepayers have never received any tangible benefit from the Pathfinder plant. In fact, ratepayers have already paid over $24 million for Pathfinder, a plant which has not been used or useful for the provision of electric service for over 20 years.

98. The decommissioning of Pathfinder will offer no guidance for the decommissioning of Monticello or Prairie Island (NSP's other nuclear facilities) because Pathfinder has been inactive for 23 years and any nuclear material remaining there has, at worst, background levels of radioactivity. Monticello and Prairie Island are likely to have substantially higher levels of radioactivity when they are decommissioned.

99. The Pathfinder nuclear facility is not "used or useful" as required by Minn. Stat. 216B.16.

100. Personnel at the Monticello and Prairie Island plants did not and do not benefit from what NSP may have learned at Pathfinder. The decisions to build Monticello and Prairie Island were made before Pathfinder was shut down, the facilities use different technology than Pathfinder did, and Pathfinder could not be used for operations training because of its poor long-term availability.

101. NSP maintains that the test year is the optimal time to undertake decommissioning of Pathfinder. Pathfinder is currently in containment status (SAFSTOR). The Company maintains that NRC regulations now requiring the eventual dismantling of facilities in SAFSTOR were not known to it before the pendency of this proceeding.

102. NSP maintains that it will save money by shipping the nuclear waste from the Pathfinder plant, radiation levels of which are now at or near background levels, as soon as possible. The remaining low-level radioactive waste can currently be shipped to a facility near Richland, Washington, at a significant savings compared to the cost that would be incurred if further delay was required. Because future availability of low-level waste disposal facilities is uncertain, and the costs to ship such waste to one of the newer facilities are projected to be significantly higher, the Company wants to proceed with decommissioning at the present time.

103. NSP maintains that Pathfinder was a highly successful research and development project that allowed it to develop and obtain considerable invaluable insights into the then-emerging technologies associated with nuclear power plants. In addition, the Company argues that Pathfinder provided invaluable training to NSP employees, many of whom still work in the nuclear generation phases of the Company and who have, in turn, provided significant training to newer employees.

104. The nuclear reactor facility at the Pathfinder plant has not produced electricity for NSP's system. The plant was shut down after an accident in September of 1967, before which time it had only been operating during testing procedures.

105. Subsequent to the accident, NSP settled its dispute regarding Pathfinder with Allis-Chalmers Company, the manufacturer of the failed unit, for $3 million. The DPS maintains the settlement was for an insufficient amount and that NSP could or should have anticipated the costs of dismantling when it negotiated the settlement. NSP argues that the $3 million settlement was for an appropriate amount and that there is no evidence showing that it could or should have anticipated the costs of dismantling at the time of negotiating the settlement.

106. There is no evidence that NSP received any insurance recovery for its losses at Pathfinder connected with the failure of the nuclear powered unit manufactured by Allis-Chalmers. NSP

contends that the issue of whether it should have attempted to recover insurance regarding Pathfinder is irrelevant to this case.

107. NSP maintains that its proposal to decommission Pathfinder is appropriate at this time because no requirement for dismantling existed in 1976 (when the Commission decided docket number E-002/GR-76-934 and, as part of that decision, Pathfinder construction costs were allowed). The Company takes the position that until 1988, NRC regulations and rulings permitted utilities to maintain nuclear units in SAFSTOR.

108. The Pathfinder construction permit was issued on May 12, 1960, and an operating license was issued by the Atomic Energy Commission (AEC) in March 1964. At the time of the September 16, 1967, incident which shut the plant down, 100% power testing had not been completed at Pathfinder.

109. After receipt of its operating license and through the September 16, 1967 incident which shut the plant down, operation of Pathfinder was extremely intermittent. The plant experienced numerous system and equipment difficulties and had a significant number of shutdowns. The Company reported to the AEC that it had difficulties with pressure control system hardware, steam flow meters, leakage from the main steam isolation valve, off-gas system hydrogen concentrations, faulty scrams, and undependable operation of the control rod drives. These operational difficulties and equipment shortcomings during the years of operation resulted in a large number of reactor shutdowns.

110. NSP accepted an "in-service" date of August 1, 1966, from Allis-Chalmers. The Company announced in May of 1966 that Pathfinder was in "commercial operation". However, the plant had yet to undergo successful start-up testing, or to reach the 100% power level and prove its continued capability to do so as of May 1966.

111. NSP wrote to the AEC on April 14, 1967, and noted that the AEC had "terminated its super heat development program". As a result, there was "no industry interest in the super heat concept". The Company noted that data generated by the continuation of Pathfinder post-construction research and development programs would be of "little or no use" because of the already highly-developed technology of water reactors.

112. One-hundred percent power was achieved by the Pathfinder reactor for about 30 minutes on September 12, 1967. However, Pathfinder ceased operations following the failure of a steam separator on September 16, 1967.

113. In an internal memorandum issued by NSP's power production department on April 30, 1968, entitled Pathfinder Atomic Power Plant Portrayal as a Training Facility, the Company's general superintendent of power production declared ". . . We have not given any serious consideration to use of Pathfinder as a training facility. Although we had counted upon it as a training facility for our Monticello and Prairie Island personnel, it has let us down in this respect and we find it

necessary to secure operator training by other means."

114. The Prairie Island nuclear power units are pressurized water reactors, which have very little in common with the reactor at Pathfinder.

115. Only three people received training at Pathfinder who subsequently worked at Monticello for a significant period of time after Monticello was in commercial operation. The reactor at Monticello uses different technology than that at Pathfinder.

116. Pathfinder did not provide sufficient benefits to NSP's ratepayers such that they should now pay for the decommissioning of the plant's nuclear reactor. In summary, Pathfinder was an experimental research and development project and never an operable nuclear power plant.

Discussion

The Administrative Law Judge has concluded that NSP has not proven that Pathfinder has provided value to present ratepayers sufficient to require present ratepayers to bear any of the decommissioning expenses associated with its nuclear reactor. The $15.7 million requested by NSP in this proceeding is in addition to $9.5 million that NSP has already collected from ratepayers for abandonment and decommissioning of Pathfinder. NSP initiated the earlier request in a rate case 14 years ago. After a contested case hearing, the Company recovered from ratepayers $9.5 million in costs associated with both abandonment and partial decommissioning (placement of the facility in SAFSTOR). The Company did not advise the Commission in 1976 that a second phase of decommissioning would follow for which NSP would again seek recovery.

The Company was informed by the consulting firm of Black and Veatch in 1970 that the cost of complete decommissioning of the Pathfinder reactor would be $2,779,150. At the time, however, it chose to only partially decommission Pathfinder, using the SAFSTOR method. These facts suggest that NSP's request to set aside funds for the decommissioning of Pathfinder 20 years later, at a cost five times greater than could have been done in 1970, comes too late and would be imprudent now.

Recovery of decommissioning costs from today's ratepayers would also result in a mismatch of costs and benefits with specific ratepayers. Present ratepayers would be responsible for costs associated with Pathfinder despite their receiving no electrical services from the plant's operation. The regulatory goal of matching is contradictory to NSP's request to recover decommissioning costs from current ratepayers.

It is noted that the request to recover decommissioning costs is also too late because the passage of time has deprived the PUC of the opportunity for full and complete evaluation of the recovery NSP already has, or should have received following Pathfinder's abandonment in 1967. For instance, questions remain relating to the appropriateness of NSP's settlement with

Allis-Chalmers. The Administrative Law Judge agrees with the OAG that documents discovered by the DPS during its audit of NSP strongly suggest that NSP's $3 million settlement with the manufacturer of the nuclear reactor was an inadequate sum which was agreed upon, at least in part, to avoid adverse publicity. It is noted that a letter dated May 27, 1969, from NSP's chairman to Allis-Chalmers states that the manufacturer owed NSP in excess of $10 million for Pathfinder's failure.

NSP bears the burden of the delay in deciding the appropriateness or merits of such issues. The Company also bears the burden of proof concerning its request for decommissioning costs. It is concluded that NSP has neither justified the delay nor met its burden of proof.

Regarding Pathfinder's usefulness as a training facility, there is no evidence that any such training benefited ratepayers by an amount equal to the total decommissioning costs requested in this case. The Company produced no cost study or other verifiable breakdown of such claimed training benefits. If training benefits do not outweigh training costs, it is difficult to conclude that NSP ratepayers benefited from Pathfinder. Another consideration is that Pathfinder simply did not do the job NSP intended. A Company letter of December 30, 1968, to the chairman of the Federal Power Commission states:

> "The Pathfinder reactor has not fulfilled our expectation that the manufacturer would provide the company with an operable power plant. In addition to the specific mechanical problems which now exist, there have been extensive operating difficulties which have prevented the plant from attaining regular operation."

Pathfinder is not used and useful to today's ratepayers. Minn. Stat. 216B.16, subd. 6 (1988), requires that property be both used and useful before recovery is allowed in rates. The Minnesota Supreme Court has applied a two-part test in defining the term "used and useful":

> "Under general principles of utility law, the 'used and useful' standard simply requires (1) that the property be 'in service' and (2) that 'it be' reasonably necessary to the efficient and reliable provision of utility service."

Senior Citizens Coalition of Northeastern Minnesota v. Minnesota Public Utilities Commission, 355 N.W.2d 295, 300 (Minn. 1984).

Pathfinder has not been "in service" since it ceased operation in 1967, with respect to its nuclear capability. NSP argues that Pathfinder was at one time "used and useful" but such an argument does not justify the inclusion of Pathfinder costs in rates because the plant must be used and useful during the test year. Additionally, the used and useful standard holds true for expenses as well as rate base items. Philadelphia Elec. v. Pennsylvania Public Utilities Commission, 61 P.A. Comm. Ct. 325, 433 A.2d 620, 625 (1981); Citizens Action v. Northern Indiana Public Service Company, 485 N.E.2d 610 (Ind. 1985), cert. denied

106 S.C. 2239 (1986). In Citizens Action, the Indiana Supreme Court stated:

> "Any allowable operating expenses must have a connection to the service rendered before it can be recovered through retail rates. This connection is established when the operating expense is incurred as a result of the process whereby existing 'used and useful' property . . . is employed to produce the product or commodity . . . ratepayers receive." Id., at 614.

In Citizens Action, the utility, like NSP in this case, characterized a cancelled plant "as a reasonable undertaking by (the utility) to meet its duty to serve". Id., at 614. The Court rejected that reasoning, calling the commission's approval of such expenses a charge to consumers "for reasonable and prudent attempts at service that fail and that provide no benefit to ratepayers." Id., at 614.

Regardless of whether Pathfinder was used and useful at one time, its nuclear reactor is not now in service and has not been in service for over two decades. The expenses related to the decommissioning of Pathfinder's nuclear operation do not provide any service to NSP's customers. Therefore, no costs relating to such decommissioning should be included in rates.

Graystone

117.
NSP has made investments through its subsidiary, Graystone Corporation, to explore the formation of a joint venture to manufacture nuclear fuel at lower costs than such fuel is now available. NSP and four other companies are studying the feasibility of building and operating a uranium enrichment plant.

118.
NSP argues that ratepayers should have the opportunity to participate in the risks and the rewards of the Graystone Project. If NSP's investment in Graystone were to be treated as a non-regulated investment, the Company maintains that the risks and rewards should then inure solely to the shareholders. In this rate case, NSP proposes that an additional $979,000 be included in the rate base for the Graystone investment, with associated expenses of $55,000 during the test year.

119.
MEC argues that while the uranium facility may benefit ratepayers, no benefit will occur until the plant is placed in service. Therefore, the costs of the plant are unnecessary to the provision of the electric service in the meantime (during the test year) and are unrecoverable as operating expenses. The DPS maintains that Graystone's cost should be excluded because the costs are similar to those incurred in NSP's refuse-derived fuel (RDF) operations, an unregulated activity.

120.

MEC recommends treating the Graystone costs as Preliminary Survey and Investigation (PS&I) costs. The PS&I account typically reflects feasibility-type costs in advance of construction. MEC maintains that since Graystone expenses today are such feasibility-type costs, PS&I costing is the appropriate treatment. Such treatment would allow the PUC more information about the project's future benefit to ratepayers, after NSP makes its decision whether or not to proceed with the project. MEC maintains that such a step at this early stage in the development of Graystone is appropriate, so that the Commission has the best information when NSP seeks to obtain rate base treatment for the facility in the future. For this test year, NSP's proposal to include operating expenses of $55,000 and add $979,000 to the rate base should be rejected, MEC contends.

121.
The DPS argues that Graystone is similar in concept to NSP's RDF operations. In docket E-002/M-84-790, an opinion rendered on NSP's request to consider refuse derived fuel facilities as regulated utility property, the Commission stated that for utility property to be included in rate base, the property must be "used and useful in rendering service to the public". Citing Minn. Stat. 216B.16, subd. 6 and Senior Citizens Coalition of Northeastern Minnesota v. Minnesota Public Utilities Commission, 355 N.W.2d 295 (Minn. 1984), the Commission declared that "used and useful" meant (1) that the property must be "in service"; and (2) that it be "reasonably necessary to the efficient and reliable provision of utility service". It is appropriate for the Commission to use the same reasoning in deciding on NSP's proposal to include Graystone in this rate case as it did regarding RDF in 1985.

122.
NSP has not shown that its investment in Graystone is reasonably necessary to the efficient and reliable provision of utility service. NSP can procure enriched uranium from another source, the U.S. Department of Energy. Ratepayers should not bear the risks and costs of developing an alternative to this fuel source.

123.
The costs of owning and operating RDF facilities are not included in the regulated operations of the Company. However, NSP can recover the cost of fuel purchased from such facilities and the contract executed between the regulated and unregulated portions of the Company is subject to regulatory review. Similarly, if NSP pursues Graystone, the contract executed between Graystone and NSP would be subject to regulatory review, and, if approved, NSP could then recover the cost of fuel purchased from Graystone as long as the expenditures are prudent.

124.
It is appropriate to classify Graystone as a PS&I item, thus excluding it from the rate base and operating expenses during the test year.

Economic Development

125.
The Company has included $897,000 in land investments for economic development in rate base and $453,000 in its income statement for such economic development expenses as community funding, customer assistance and information, land utilization and business attraction.

126.
NSP's proposal regarding economic development costs is opposed by MEC, the DPS and the OAG. All parties point out that, although the 1988 Rate Case Stipulation allowed for a 50-50 split of economic development costs between shareholders and ratepayers, the PUC disallowed economic development costs in its June 23, 1988 decision in that docket. MEC argues that ecomomic development costs are simply advertising expenses specifically disallowed by statute. Minn. Stat. 216B.16, subds. 8(c) and (d) were relied upon by the Commission in the last rate case, when it decided to remove economic development costs in their entirety. The Commission held that NSP had not demonstrated a strong enough connection between economic development and the statutory factors (including the public's need for adequate, efficient and reasonable service and the utility's need for sufficient revenue to enable it to supply such service, including its need to earn a fair return on its investment) to allow inclusion of economic development costs. Docket E-002/GR-87-670, Order at 21.

127.
Minn. Stat. 216B.16, subd. 6 also requires that adequate provision for depreciation of utility property "used and useful" and rendering service to the public be given due consideration by the Commission. In this case, the Intervenors argue that NSP has made no showing that the land investments for economic development are used and useful in providing electricity, as they must be in order to be included in rates.

128.
NSP has not demonstrated a connection between its economic development programs and the provision of utility service, as required by the Commission in the Company's last rate case. In addition, the Company has not demonstrated that its economic development investment is cost-effective.

129.
NSP has not met its burden of showing that it is just and reasonable for ratepayers to bear the costs of its economic development programs. The proposed $453,000 in operating expenses and $897,000 addition to rate base for Economic Development Investment is appropriately denied.

Unburned Nuclear Fuel

130.
At the end of NSP's three nuclear reactors' (one at Monticello, two at Prairie Island) productive lives there will remain, according to NSP, a total unrecovered balance of unused nuclear

fuel in the amount of 123.1 million dollars. NSP maintains further that the fuel remaining at the end of these plants' lives cannot reasonably be salvaged.

131.
NSP proposes to adopt a sinking fund amortization in order to build a reserve to recover the cost of unused nuclear fuel over the remaining lives of the three nuclear plants and to avoid charging the total amount to customers who are on the system at the end of the lives of those plants. The Company maintains that such a system of recovery would avoid over-recovery from customers who would not continue to benefit from the plants.

132.
North Star and the DPS both oppose recovery from ratepayers in the form of expenses and amortization for the unrecovered balance of unused nuclear fuel in this rate case. The Intervenors maintain that too little is now known about relevant facts, such as whether there will be unused nuclear fuel at the end of the useful lives of the plants and how much of a time horizon is involved in measuring the useful lives of the plants, to merit the setting aside of expenses and amortization costs in this rate case. In addition, the Intervenors maintain that NSP's assumption that any remaining fuel will have no salvage value has not been proven.

133.
The DPS argues that the question of nuclear fuel recovery is an item that relates to nuclear plant decommissioning. Consequently, the costs should be considered in the context of NSP's next nuclear decommissioning study and excluded from the rate case.

134.
North Star argues that because NSP has proven neither that there will be unspent fuel which is worthless and cannot be salvaged, nor that now is the optimal time to begin recovering this speculative expense, the proposed unburned fuel expense recovery be delayed until future rate cases.

135.
NSP offered no studies to support its position regarding unburned nuclear fuel in this record. North Star argues that forcing current ratepayers to pay for a contingency that unburned fuel may remain is unfair, and that NSP's proposal is improper from an accounting perspective because it would amortize an unknown cost over an unknown period of time.

136.
MEC argues that, because NSP plans to attempt to extend the lives of Monticello's and Prairie Island's Nuclear Reactors, all of the unburned fuel accounted for in the 123.1 million dollar amortization request may be used before Monticello and Prairie Island are shut down. In addition, there is no evidence that technology will not advance in the next 25 years to allow the unburned fuel to be sold or salvaged.

137.

It is appropriate to reject NSP's proposal for unburned nuclear fuel recovery because the expense is too speculative and has not been shown to be appropriate for amortization during the 1990 test year. Rejection of NSP's proposal reduces operating expenses by $1,641,000 and increases NSP's net rate base for the test year by $497,000.

Repairs on Manitoba Hydro Line

138.
NSP is incurring a 6.5 million dollar total company cost to replace spacer-dampers on a 500 kV transmission line connecting the Utility with a Canadian utility, Manitoba Hydro. Spacer-dampers are a brace-like device that maintain the spacing between conductors on a transmission line and act as shock absorbers to dampen high frequency oscillations.

139.
All 14,000 spacer-dampers on the Manitoba Hydro Line need replacement. The new equipment is expected to last for 30 to 35 years. The need to replace them was not discovered until September of 1989.

140.
NSP proposes to amortize the costs relating to the 500 kV transmission line over a period of three years. MEC recommends depreciating the costs over the remaining life of the line because the usefulness of the redesigned spacer-dampers will exist for the remaining life of the line. MEC's argument is based, in part, on the notion that NSP's requested treatment does not properly match costs and benefits. The parties also dispute whether the redesign of the transmission line is a substantial betterment that qualifies as an item that should be amortized, rather than a normal expense for maintenance.

141.
MEC proposes to reduce NSP's operating expenses by $1,812,000. The appropriate adjustment to rate base if MEC's proposal is adopted would be to add $2,789,000 for the 1990 test year.

142.
NSP's proposal to amortize the replacement of spacer-dampers on the 500 kV transmission interconnection with Manitoba Hydro is reasonable. Replacement of spacer-dampers constitutes repair and replacement of "minor units of property" as defined in the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts.

143.
In order to spread the amorization out over the period requested by MEC, replacment of the spacer-dampers must qualify as a "betterment" under the Uniform System of Accounts. The transmission line, as originally constructed, contained spacer-dampers. The replacement of those spacer-dampers with other spacer-dampers does not improve the capacity or efficiency of the line, but simply repairs the deficiency in the existing spacer-dampers.

144.
MEC's proposal to amortize the spacer-dampers being replaced on the Manitoba Hydro Line over 30 to 35 years (the estimated remaining life of the line) should be rejected. NSP has shown that its proposal for expensing the costs over a three year period (to avoid any greater impact on rates than appropriate) is just and reasonable.

145.
The Suburban Rate Authority argues that the cost of replacing the spacer-dampers should be rejected because the cost estimates are vague and costs have not been incurred. The Suburban Rate Authority's brief makes no reference to the record in support of these arguments. The testimony of NSP witness Ewers to the effect that the costs to replace the spacer-dampers are reasonably forecasted to be $6.5 million and will be incurred during test year 1990 remain unchallenged on the record.

King Plant Rotor

146.
As part of this rate case NSP proposes a five-year amortization of the cost of the replacement rotor at the Allan S. King Generating Plant, and that the unamortized balance be included in rate base.

147.
The Company originally planned both to replace and to refurbish a damaged rotor at the King Plant in order to retain it as a spare part. In the last NSP rate case (Docket E-002/GR-87-670) the Commission allowed the cost of the new rotor to be capitalized and included in rate base. Subsequent analysis showed that the old rotor could not be economically refurbished. Consequently, the Company proposed that it was appropriate to capitalize the cost of the new rotor. Under generally-accepted accounting principles, the replacement cost would normally be expenses in the year in which it was incurred.

148.
In 1988, NSP proposed to the Commission that the cost of the new rotor, which had previously been included in rates as a capitalized project, be capitalized over 5 years. In Docket E-002/M-88-923, the PUC decided, on December 15, 1988, to approve NSP's proposed amortization. On February 23, 1989, the Federal Energy Regulatory Commission also approved the five-year amortization method.

149.
MEC argues that the King Rotor amortization expense ($2,187,000) proposed in this case should be excluded from NSP's cost of service. In addition, MEC proposes that the rate base for test year 1990 be reduced by $2,839,000.

150.
MEC argues that NSP's proposed treatment of the King Rotor expense represents an improper attempt to recover a past

operating cost that is not representative of the period for which rates are being set (the 1990 test year). Since the rotor repairs were completed in June 1988, and NSP does not expect to incur any cost with respect to removal and repair of the King Rotor during the test year, MEC maintains that the repair and replacement costs are not representative of the period for which rates are being set, and the inclusion of such costs would violate basic rate making principles, which hold that a utility may not set rates to recoup past losses.

151.
MEC characterizes the Commission's Order of December 15, 1988 in Docket E-002/M-88-923 as merely approving an accounting change, with reservation of a determination on ratemaking treatment.

152.
MEC maintains that NSP's proposal to account for the cost of the new rotor by amortizing the expense over five years is merely a change in plans that involves new accounting treatment. NSP argues that once the decision was made to amortize, rather than expense the King Rotor repair and replacement costs that it would be completely unfair to change the methodology in the middle of the amortization period and deny the full return of the investment through either mechanism.

153.
The Administrative Law Judge agrees on this issue with NSP. The Commission's "reservation" of determining of ratemaking treatment in its Order of December 15, 1988 is interpreted to mean simply that Docket E-002/M-88-923 was not a rate case and that the Company would have to wait until it filed its next rate case before the effect of the newly-approved accounting methodology would appear in rates. It is appropriate to reject MEC's proposal to disallow the amortization expense and rate base treatment for an obviously prudent expense such as replacement of the King Rotor.

154.
MEC's contention that the King Rotor replacment should be treated as any other operation or maintenance cost, and expensed in the year incurred, has the effect of excluding the cost since it was incurred prior to the test year. Such analysis ignores past regulatory treatment of these costs and would be inappropriate. No Intervenor objected to NSP's prior capitalization of the costs, or its subsequent request to commence the amortization. The Administrative Law Judge agrees with NSP that it is now too late to "redo history" and treat these costs as though they had been expensed in a prior period.

Rate Case Expenses

155.
NSP proposes a two-year amortization period for rate case expenses. The DPS argues that appropriate recovery of rate case expenses in this case calls for reducing the annual expense and rate base. The Department advocates a recovery period of three years instead of NSP's proposed two-year period and exclusion of

unamortized rate case expenses from the rate base on the theory that rate case filings benefit shareholders only.

156.
The DPS recommends the first adjustment because rate case expense amortization periods should correspond to the time period during which new rates are in effect.  The Department believes that there is no reason to assume that a new rate case will be filed sooner than three years after the current case was filed.

157.
NSP asserts that the amortization period for rate case expenses should be computed based on the average history of NSP's rate case filings since the Commission has been in existence. Moreover, NSP argues that current contracts calling for the purchase of new electric capacity in mid-1992 and mid-1993 may require future rate filings.

158.
The DPS's argument that the average period between NSP filings over the last twelve years since 1978 is once every three years excludes the 1987 filing.  The Department maintains that Docket 87-670 should not be considered because the filing was made to pay for the Sherco 3 Plant.  The Administrative Law Judge is unable to make a distinction for the Sherco 3 filing because such a filing also generates expenditures for conducting a rate case.

159.
NSP's proposed two-year amortization of rate case expenses is reasonable.

160.
DPS's assumption that NSP will not be filing a rate case every other year is inconsistent with history and fails to take into account the shortfall that occurs when, as with the 1987 NSP rate case, the amortization period is too long and overlaps with the filing of the next rate case.

161.
The expenses associated with a rate case filing are indispensable to the conduct of utility business and the continuing provision of utility service.  Rate case expenses are made necessary by the requirement that rates not be changed except by a rate case, and thus the expenses inure to the benefit of ratepayers.  There is no guarantee that a filing of a rate case by a utility will result in a rate increase.  The last Minnesota Power rate filing resulted in a decrease in rates for the utility.

162.
It is appropriate to reject the DPS proposal to exclude $110,000 of rate case expenses from test year operating expenses and to reduce rate base by $493,000.

Decommissioning Cost Accruals

163.
NSP has, for several years, developed an internal sinking fund for the costs associated with the ultimate decommissioning of

NSP's three nuclear facilities.

164.
NSP's proposal for nuclear decommissioning funding, as filed in this rate case, complies with NRC rules and relevant Internal Revenue Service rules.

165.
The use of a 6% escalation rate for nuclear decommissioning, to convert 1986 costs to future dollars, is appropriate.

166.
The inclusion in decommissioning costs of the costs of dismantling non-contaminated portions of the nuclear plants is appropriate.

167.
The Nuclear Regulatory Commission has determined that external funding for decommissioning costs must be implemented, through an external sinking fund mechanism, effective August 1, 1990.

168.
Minnesota Energy Consumers, through their witness Derrick Dahlen, disagrees with NSP's nuclear decommissioning fund proposals. Dahlen considers it far too speculative to assume a 6% escalation rate over the remaining lives of the Monticello, Prairie Island 1 and Prairie Island 2 facilities, which requires an estimate of future inflation over a 25-year time period. Dahlen believes it is not necessary to predict long-term inflation for a nuclear decommissioning cost recovery program.

169.
MEC proposes that the Commission require NSP in each rate case between now and the actual decommissioning of its nuclear facilities to: (1) escalate decommissioning cost estimates to the test year, excluding costs related to non-contaminated portions of the facilities; (2) adjust the decommissioning cost estimate by subtracting out (a) amounts previously collected, and (b) amounts earned on funds previously collected (with investments being managed by an independent professional); (3) estimate the remaining life (the time until decommissioning); and (4) divide the amount remaining to be collected by the estimated remaining life.

170.
MEC contends that its approach solves the problems associated with NSP's proposal and the NSP proposal as it is endorsed by the Department of Public Service. MEC's approach is advocated because it allegedly avoids the accrual of amounts determined by estimates of future inflation and estimates of future earnings of invested funds.

171.
MEC believes there is no reason to include costs of removing non-contaminated portions in the costs of decommissioning NSP's nuclear facilities because the NRC requires removal only of contaminated portions of a facility, so that a facility may be removed from service and residual radioactivity reduced to a

level that releases the property for unrestricted use.

172.
DPS witness Linscheid points out that the factors affecting the decommissioning cost accrual (tax adjusted internal rate of return, capital structure, income tax rates, the funding plan, the cost escalation rate and the remaining lives of the nuclear plants), and the appropriate relationship of those factors as proposed by NSP in Docket E-002/D-89-911, are still valid for the first seven months of 1990.

173.
The DPS also believes that external fund decommissioning accruals (effective August 1, 1990) should be included in this rate case.

174.
In order to calculate decommissioning accruals for the final five months of 1990, NSP incorporated 1991 as a test period for calculating decommissioning accruals because 1991 will be the first full year that external funding is required and therefore is the representative period.

175.
NSP asserts that the amount it has proposed for recovery for the nuclear decommissioning during the last five months of 1990, based on a proportional breakdown of its annualized cost for 1991, must be recalculated to conform to the ultimate rate of return determination in this case.  The Company suggests that for purposes of any refunds of interim rates, this annualized cost could be adjusted to offset against refunds only the costs forecasted to be incurred in 1990.

176.
It is appropriate to accept NSP's proposed accrual amounts for nuclear decommissioning for the 1990 test year, as well as its proposal to offset against refunds the costs forecasted to be incurred in 1990, adjusted appropriately to conform to the ultimate rate of return determination.

177.
It would be inappropriate to adopt MEC's proposal to adjust the jurisdictional nuclear decommissioning cost accrual by $13,248,000, to a level of $17,779,000.  The depreciation expense finally proposed by NSP for nuclear decommissioning accruals is appropriate.

178.
DPS's proposal to hold a hearing under a separate docket as the appropriate forum for resolving any issue regarding updated decommissioning cost studies, with the results of that proceeding used in the rate case proceeding following the resolution of the updated cost studies, is appropriate.

179.
MEC's suggested solution to the nuclear decommissioning fund accrual issue would shift too many costs to future ratepayers.

180.
Inclusion of dismantling costs for non-contaminated components is appropriate. Removal costs associated with non-contaminated components at NSP's nuclear plants fall into the category of property subject to accrual. In addition, the depreciation Orders issued to date by the Commission have included as a component of the depreciation rate the estimated net salvage value of the asset being depreciated. Every PUC nuclear decommissioning Order has included as a part of the decommissioning cost estimate the removal of non-contaminated components, and it is appropriate to continue with such a procedure.

181.
North Star proposes reduction in NSP's decommissioning expense of $5,211,000 because it asserts that NSP's proposal mismatches 1991 expenses with 1990 revenues. The mismatch asserted by North Star has not been proposed by NSP, whose proposal to implement 1991 decommissioning cost estimates only extends to "annualizing" those expenses for the last seven months of 1990. Therefore, the alleged mismatch has not occurred in NSP's proposal.

182. North Star maintains that NSP's decommissioning expense for the test year should be reduced by $5,211,000, the difference between the proposed $42,199,000 (1991 expenses) and 1990 test-year forecasted expenses of $36,988,000. North Star's concern is misplaced. A review of the testimony of NSP witness Robinson makes it clear that the $42,199,000 figure is the annual accrual for decommissioning expense throughout NSP's total Minnesota company. The figure has not been reduced by an allocation to the Minnesota jurisdiction.

183.
It would be inappropriate to reduce NSP's decommissioning expenses for test year 1990 by $5,211,000 on the basis of North Star's allegation that 1991 expenses are used instead of 1990 expenses for nuclear decommissioning.

Midwest Compact Fee

184.
The Midwest Compact Fee is a fee for pre-operational funding of a low-level radioactive waste disposal facility currently proposed to be built in Michigan. The fee is based on the Compact's annual revenue requirement, prorated according to the amount of each utility's waste that is expected to be shipped for disposal from the Midwest Region. NSP's share of the revenue requirement is 14.23%.

185.
The Midwest Compact has a fiscal year that begins July 1. At the time of the close of the record in this case, the Compact's revenue requirement for fiscal year 1991 was anticipated, according to the DPS, to be revised downward from the preliminary estimate of $19.5 million to about $10 million. For the past two years, the Compact has revised its revenue requirement downward by about one-half of its original estimate.

186.
NSP proposed inclusion in test year expenses the sum of $1,355,000 for its obligation to the Midwest Compact. This estimate presumes that the July 1989 projection of $19,453,908 for the Compact's budget for 1991 will be the final amount budgeted.

187.
It is appropriate to adopt the DPS proposal, which is based on the historical trend to halve (approximately) the original projections for the Midwest Compact budget. As a result, expenses should be reduced for the test year by $585,000.

NRC License Fees

188.
NSP proposes inclusion in test year expenses the sum of $3,900,000 for its Nuclear Regulatory Commission license fees.

189.
Federal law requires that members' fees for the first three quarters of 1999 be based on a 45% recovery of the overall NRC budget. NSP contends that it is reasonable to anticipate that Congress will require a 100% recovery for the last quarter of 1990.

190.
The DPS, OAG, MEC and North Star all oppose NSP's request for a 45% recovery of the overall NRC budget for the first three quarters and a 100% recovery for the last quarter. The OAG contends that NSP is speculating that Congress will approve funding of NRC fees at a 100% recovery rate in the fourth quarter of 1990. The Omnibus Budget Reconciliation Act of 1987 requires a 45% recovery rate for fiscal years 1988 and 1989, after which the NRC's collection authority reverts back to the pre-Act level of 33%. Since Congress has not taken any specific action for fiscal year 1991, the Intervenors argue that it is inappropriate to assume a 100% recovery rate for the final quarter of 1990.

191.
Intervenors DPS and OAG propose that the NRC license fee recovery be set at 45% for the first three quarters of the test year and at 33% for the final quarter, since such treatment follows current law. North Star and MEC advocate computing NRC user fees on the assumption that a 45% funding level will pertain throughout the test year.

192.
It is appropriate to set NSP's NRC license fee recovery at 45% for the first three quarters of 1990 and 33% for the final quarter. Such treatment reduces NSP's request for inclusion in test year expenses for NRC license fees of $3,900,000 to $2,788,000. As a result, it is appropriate to reduce test year expenses for NRC license fees by $1,112,000. The reduction is 28.5% of $3,900,000, which is the proportionate reduction from

four quarters at 45% and one quarter at 100% to three quarters at 45% and one quarter at 33%.

Unbilled Revenues

193.
The OAG argues that NSP's test year revenues do not reflect the full amount of revenues associated with the sale of electricity during the test year. However, all costs related to the sale of electricity during the test year are included. The OAG proposes an adjustment to reflect what it believes to be the proper amount of test year revenues.

194.
At the end of any given month, NSP records all expenses associated with providing electricity to customers that month. However, the Company has not recorded all revenues associated with that electricity, due to the lag time involved before those revenues are billed to its customers.

195.
The OAG contends that greater revenue is usually left unbilled at the end of each December than is offset by amounts NSP receives in January of the same year, due to increased electric usage or an increasing customer base.

196.
The OAG argues that for the test year, end-of-the-year unbilled revenues amount to $63,250,000, whereas beginning-of-the-year unbilled revenues are only $59,705,000. The difference, $3,545,000, is proposed for inclusion in revenues for the 1990 test year. Such inclusion would lower NSP's revenue requirement.

197.
NSP argues that the recognition of such unbilled revenues would amount to a fundamental change in regulatory and accounting policy affecting all utilities and should only be considered in a generic proceeding.

198.
The PUC recognized and ordered an unbilled revenue adjustment in NSP's last gas rate case, an adjustment that actually raised rather than lowered NSP's revenue deficiency. See page 24 of the Commission's Order in docket G-002/GR-86-160.

199.
Based on its own study, NSP contends that its balance of unbilled revenues will actually decrease at year end 1990 by $5,399,000. The calculation is based upon an actual beginning balance of $59,704,667 and an ending balance of $54,305,898. Inclusion of this amount in rates would raise NSP's revenue requirement. The Company maintains, however, that such an adjustment would be improper.

200.
The OAG calculated its end-of-the-year unbilled revenues of $63,250,000 on the assumption that the ending balance should be

changed by the same amount by which the actual beginning balance exceeded NSP's forecasted beginning balance for 1990. NSP's actual beginning balance was larger than its forecast, in part, because December of 1989 was colder than normal. The OAG's proposed adjustment would be supported if there were a basis to conclude that the weather in December of 1990 will also be much colder than normal. Since there is no factual basis for that assumption, and for the purposes of test year forecasting, the use of normal weather is presumed, the estimate offered by NSP for an end-of-the-test-year unbilled revenue balance is more appropriate.

201.
NSP's contention that the OAG's proposal would match 12-1/2 months of revenue with only 12 months of expenses is misplaced. The OAG has based its proposal upon the difference in anticipated end and beginning-of-year margins. However, it would be inappropriate to adopt the OAG proposal because NSP does recognize 365 days of revenues and 365 days of expenses in the test year under its accounting and ratemaking methods and it has established that its balance of unbilled revenues will actually decrease at year-end 1990. NSP has established that its system of matching 365 days of revenues and expenses is just and reasonable.

Chippewa Land Sale

202.
In 1988 and 1989, NSP-Wisconsin, a wholly owned subsidiary of NSP, sold more than 8,500 acres of land it owned at the Chippewa Flowage in Wisconsin to the State of Wisconsin and to the federal government. NSP-Wisconsin (NSP-W) realized a before-tax gain of just under $8,600,000 on the sales and an after-tax gain of $5,588,000.

203.
NSP purchased the land in 1920 for less than $5.00 per acre, and held it as a part of its original federal license requirement, which requirement was lifted in 1984.

204.
The land became available for sale when the FERC license on the Flowage expired and NSP obtained an exemption from FERC for future licensing.

205.
The OAG and North Star argue that the gain on the sale of land should be shared with Minnesota ratepayers. They advocate an adjustment whereby NSP's rate base for the test year would be reduced by $3,151,000 and net operating income would be increased by $1,576,000.

206.
The Intervenors maintain that the land was acquired for a public utility purpose and recorded in a utility plant account for most of the time it was held by NSP (until 1987). Therefore, the

costs associated with the Chippewa Flowage facility were passed on to ratepayers during that time. The statement by the Company that the land was not included in utility property "prior to its transfer to non-utility property" creates, for the Intervenors, an inference that the property was utility property prior to 1987. In addition, under Wisconsin law, property taxes are not assessed against utility property. However, local property taxes were assessed against the land for 1987 and 1988, creating a further inference that if local property taxes were assessed only in 1987 and 1988, the land was utility property prior to 1987.

207.
NSP has not shown that the Chippewa Flowage land was placed into a non-utility account at the time of the original purchase. From this, the Intervenors infer that the land was included in NSP-W's rate base, upon which ratepayers paid a return. The Intervenors argue further that Minnesota ratepayers supported the land through payment of electric rates. Their conclusion is based on an assertion that prior to the sale, NSP-W leased the land to its subsidiary, Chippewa and Flambeau Improvement Company (CFIC). CFIC controlled the water flowage through the area and charged utilities for the use of the water. NSP used the water for the generation of electricity. Therefore, the water tollage charged by CFIC was part of NSP-W's cost of producing power, which cost flowed through the Interchange Agreement between NSP-W and NSP-Minnesota and, therefore, was in part paid for by Minnesota ratepayers. NSP argues that the gain on the sale of land, even as to NSP-W, was for the benefit of shareholders, not ratepayers, since NSP-W's ratepayers never provided to shareholders a return of the investment in the land. The Company notes that tolls paid to CFIC were for use of the water in the Flowage, not of the surrounding land.

208.
In the past, NSP has flowed through losses incurred on the disposal of property acquired for a public utility purpose. For example, Minnesota ratepayers paid for the amortization of the cost of the abandonment of the Tyrone nuclear project. The Intervenors argue that NSP should treat its gain on sale of the Chippewa land in a consistent manner.

209.
NSP also argues that ratepayers should not share in the gain because land is not a depreciable asset and ratepayers do not pay a return on land based on the market value of the property. The Intervenors maintain that depreciability is irrelevant to the issue of whether or not NSP ratepayers should share in the gain because, while land which is included in rate base must be included only at original cost, Minn. Stat. 216B.16, subd. 6, does not exclude non-depreciable property from rate base.

210.
The OAG argues that the PUC has determined that any gain on utility property belongs to the ratepayers, and that the Commission has not excluded land as an exception to that principle. In support of this proposition, the OAG cites the Commission's Order in Minnesota Power's last rate case (Docket E-015/GR-87-223) where the Commission ordered that gains on

utility properties belong to the ratepayers. It is noted that in that case, Minnesota Power (MP) did not propose to segregate the sales of land regarding either the sale of a 40% share of its Boswell 4 power plant to NSP or in accounting for gain on the sale of MP's ownership interest in the Coyote plant.

211.
The OAG notes further that NSP's argument that the Uniform System of Accounts dictates that the gain must be given to shareholders is contradicted by the ruling of the Minnesota Supreme Court in In the Matter of the Petition of Continental Telephone Company of Minnesota, 389 N.W.2d 910 (Minn. 1986) wherein the Court stated ". . . It seems to us that income derived from any asset which is a part of the rate base must be recognized in the determination of the petitioning utility's revenue requirements, regardless of whether the asset is a telephone system that generates ordinary operating income or cash working capital which earns interest . . . Nothing in the federal regulations or the Minnesota rules suggests that the system of accounts is determinative of the treatment of any item for purposes of setting rates or that the system deprives MPUC of its power or absolves it of the duty to decide the issues before it and to set just and reasonable rates." 389 N.W.2d at 915.

212.
NSP contends that the Commission cannot pass through the gain to Minnesota ratepayers unless the Interchange Agreement is amended by FERC. The Intervenors respond that amendment of the Agreement must be initiated by NSP. NSP made such an application to FERC in connection with the abandonment of the Tyrone plant, and the Minnesota Supreme Court decided in Northern States Power Company v. Minnesota Public Utilities Commission, 344 N.W.2d 374 (Minn. 1984) that 87% of the fixed charges of the abandonment costs for Tyrone should be borne by Minnesota ratepayers. The OAG argues that NSP has deliberately failed to request such an amendment for the gain on the sale of the Chippewa Flowage land. Thus, NSP is arguably taking the position that its ratepayers stand at risk for all losses but can receive no gains. The Intervenors maintain that such a position is fundamentally unfair. The OAG also argues that if the Commission believes it lacks authority to impute the Chippewa land sale gain to ratepayers, because the Interchange Agreement is controlled by FERC, the PUC should require NSP to seek approval from FERC to share the gain with ratepayers. Under the suggested scenario, the PUC could disallow the gain for purposes of final rates but make the rates subject to refund in the event FERC approves NSP's request for sharing.

213.
The Administrative Law Judge accepts the arguments advanced by the Intervenors noted in the above Findings of Fact and finds that it is appropriate to reduce NSP's rate base by $3,151,000 and increase its net operating income by $1,576,000 for test year to reflect a flow-through to Minnesota ratepayers of an appropriate portion of the gain made by the sale by NSP-W of Chippewa Flowage land. He is not persuaded by NSP's arguments that the land was not utility property upon which Minnesota ratepayers paid a return. It is NSP that controls the approach to FERC for an amendment of the Interchange Agreement to allow a

pass-through of the gain on the land sale. The Judge is persuaded that not recognizing this gain would result in rates that are not just and reasonable and would be fundamentally unfair to Minnesota ratepayers.

Property Taxes

214. In its direct case, NSP proposed a property tax expense of $130,000.000 during the test year. Subsequent to June 1990, NSP's tax department revised its 1989 property tax expense accrual to $126,000,000 (the figure estimated at the time of filing was $122,000,000) to take into account changes in tax laws enacted by the 1989 Special Session of the Minnesota Legislature. Based on that revision, NSP's supplemental testimony revised its forecast of 1990 property tax accruals to $138,000,000, based on a nine percent escalation factor.

215. North Star objects to allowance of a nine percent annual increase rather than the $8,000,000 per year six-year average increase that had been used in NSP's original filing. It argues for an allowance of $134,000,000 for property tax expense (not $138,000,000) when results in an average increase of 8.2% for the 1988-1990 period, and that the additional adjustment proposed in NSP's supplemental testimony is unsupported and unexplained.

216. The six-year annual average increase in property tax accruals for NSP is 9.23%. Therefore, it is appropriate to allow a nine percent escalation factor. NSP has established that its property tax accrual estimate for the test year is fair and reasonable.Capacity Purchases from Minnesota Power

217. In a settlement agreement with Minnesota Power, NSP has agreed to purchase 200 MW of peaking capacity per year, commencing May 1, 1990, through October 30, 1993. Under the agreement, the charges for the purchased capacity increase every May 1.

The annualized cost associated with the Minnesota Power purchase is $2,647,000 (Minnesota jurisdiction). NSP argues that this amount should be used in determining the revenue requirement for final rates.

218. NSP's cost estimate includes increases that will not occur until 1991 respecting the purchase of capacity from Minnesota Power. NSP Exhibit 75, Schedule 10, page 3 of 3 indicates that NSP's annualization of capacity purchase costs from Minnesota Power results in expenses of $3,600,000, which is the 1991 estimated expense. The actual 1990 expense is $2,133,000. The difference, $1,467,000, is proposed as an adjustment to purchase capacity costs for final rates. The numbers in Schedule 10 have not been adjusted down to reflect allocation to the Minnesota jurisdiction.

219. It is inappropriate to allow NSP to recover its 1991 expense level during the test year for its purchase of capacity

from Minnesota Power. Expenses for the test year should be adjusted accordingly by $1,079,000 ($1,467,000 times an allocation factor of .7355).

## Research and Development

220. In its original filing, NSP allocated $93,000 to a research and development project entitled "Technical Innovation and Support Project".

221. In its Rebuttal testimony, NSP stated that it sought to reallocate the $93,000 to the Advanced Combined Cycle Project (ACC).

222. NSP's original filing contains no budgeted amount of research and development funds to support the Advanced Combined Cycle Project in 1991 and only $64,200 to support it during the test year. NSP gives no specific explanation of the actual cost NSP anticipates for the project or why the project, which was apparently expected to be completed in 1990 at a cost of only $64,200, now needs an additional $93,000.

223. The Administrative Law Judge agrees with the OAG on this issue. The OAG opposes recovery from ratepayers of $93,000 in research and development funds NSP now seeks to add to its Advanced Combined Cycle Project. It is reasonable to infer that the funds have been transferred in order to justify including the $93,000 in rates, as OAG argues. NSP has not met its burden of proof for this expenditure because the record lacks adequate support for reallocating $93,000 to the Advanced Combined Cycle Project. It is appropriate to reduce NSP's test year research and development expenses by that amount.

## Configuration Management

224. The NRC and the Institute of Nuclear Power Operation (INPO) require NSP to bring its nuclear plants up to design and document standards that were not in existence when the plants were built. NSP is committed to meet the NRC and INPO requirements through a five-year configuration management program that will cost a total of $15,000,000. In connection with this investment, NSP proposes to expense $6,400,000 during the test year.

225. MEC argues that NSP should not be allowed to expense the costs of configuration management because (1) such costs are non-recurring, (2) design and documentation standards are normally capitalized as part of the construction cost, and (3) benefits will occur over the remaining lives of the nuclear facilities. For these reasons, MEC recommends capitalizing the costs of configuration management and depreciating the total amount over the life of the nuclear facilities.

MEC proposes a reduction in test year operating expenses of $5,481,000, and an increase in the rate base of $1,637,771 to adjust for proper treatment of configuration management costs.

226. It is appropriate to include in NSP's test year operating expenses $6.4 million for the configuration management program. The amount proposed to be expended in the test year is representative of the annual amounts that will be required in the next several years for first-year design changes and enhancements at NSP's three nuclear units.

227. The Administrative Law Judge is persuaded by NSP's argument that the costs of enhancing and maintaining design and documentation standards after construction are normally expensed each year as incurred during the life of the project. In contrast, the costs of design and documentation standards which are incurred before a project is constructed or during construction are normally capitalized as part of the engineering services or overhead costs of the construction project.

228. NSP has proven that its configuration management costs incurred as required by the NRC and INPO at its nuclear power facilities (Monticello and Prairie Island) are costs of maintaining the standards imposed by regulatory agencies, which standards could change again during the life of the project. Therefore, it is appropriate to treat the configuration management costs as an expense item.

Incentive Compensation

229. MEC proposes reducing NSP's operating expenses by $7,096,000 (total Minnesota company) to exclude all incentive compensation from test year expenses, contending that the compensation has not been authorized by the Commission, is against public policy and is not reasonable and necessary.

230. NSP's incentive compensation plans are a component in NSP's comprehensive compensation system. No requirement exists, under statute or by Commission rule or practice, for prior PUC approval of incentive compensation plans or compensation systems.

231. NSP's incentive compensation plans are in the public interest and benefit ratepayers, in that they encourage improved productivity and reduced costs. The incentive compensation plan does not, either in general terms or by reference to individual performance goals, constitute "the employment of a lobbyist for compensation which is dependent upon the result or outcome of any legislative or administrative action" within the meaning of Minn. Stat. 10A.06.

232. Services performed by NSP employees who are eligible for incentive compensation are reasonable and necessary to the provision of electric utility service and the total compensation of those employees, including incentive compensation, is not excessive or unreasonable.

233. The fact that NSP's incentive compensation plan is designed to put some portion of salary at risk of not being

received unless corporate and individual goals are met, and that one of the corporate goals is that the Company earn its authorized rate of return, is not against public policy.

Tax Benefit Transfer Leases

234. In the early 1980s, NSP purchased 55 tax benefit transfer (TBT) leases to take advantage of then-existing tax laws. The TBTs have operated as a source of zero-cost financing.

235. The use of a zero-cost source of financing has allowed NSP to reduce its rates by $13.8 million during the test year.

236. NSP's shareholders accepted all of the financial risks associated with the TBTs. Ratepayers did not supply the funds for the purchase of TBTs. The funds were furnished by shareholders from retained earnings.

237. The TBTs are not used and useful in providing utility service and should not be reflected in rate base.

238. As determined above, NSP's actual capital structure should be used for the purpose of determining rate of return, and the TBTs should be included in capital structure at a zero cost. If NSP's actual capital structure were not used for the purpose of determining rate of return, and a hypothetical capital structure were used which would eliminate any return on the investment in TBTs, the TBTs should then be considered as non-utility investments and the risks and rewards should inure solely to NSP's shareholders.

239. DPS witnesses Lusti and Thompson argue that TBT leases are separate from capital structure, should be reflected in rate base and were purchased with ratepayer funds. The DPS maintains that if TBTs are not included in the current rate filing, then the tax liability for NSP's ratepayers will be greater than the actual tax liability of the Company, because the Company includes TBT credits in computing actual income taxes.

240. There is no support in the record for DPS's assertion that TBT leases were purchased with ratepayer funds. The Department's implied argument that TBTs should be included in rate base even if the Commission were to adopt a hypothetical capital structure and deny any return on the investment should be rejected.

Marketing Programs

241. The DPS recommends that expenses associated with four of NSP's off-peak sales programs, the cooking, floodlighting, security lighting and heat storage projects, be disallowed from rates.

242. The Department presented a cost-effectiveness analysis that adopts a long-term view and demonstrated that the above-listed projects failed to pass a proper cost-effectiveness analysis.

243. NSP refers to these programs not as marketing programs but as "off-peak programs". However, several of these programs contribute directly not only to the winter, but also the summer peak.

244. In NSP's last two rate cases, the Commission has required marketing programs to pass a cost-effectiveness test before a utility can charge ratepayers for these expenses.

245. NSP's cooking, floodlighting, security lighting and heat storage projects should be disallowed, resulting in a downward adjustment of NSP's marketing expenses of $230,000.

Removal of Deferred Costs

246. NSP presented evidence that it defers expenses in non-rate case years in order to prevent having to file rate cases every year. In this connection, the Company admitted deferring expenses from 1989 into the 1990 test year.

247. MEC argues that the Company has not deferred any costs from 1990 into 1991. Therefore, it contends that 1990 costs are overstated and do not reflect normal levels of operating expenses.

248. MEC argues that the 1989 expenses deferred into the 1990 test year should be removed from operating expenses for this case, presumably as a form of "compensation" for NSP's failure to make any such adjustments out of the test year in its rate case filings. After MEC's adjustment, NSP's operating expenses would be reduced by $2,997,000.

249. It is inappropriate to make the $2,997,000 adjustment advocated by MEC for expenses deferred from 1989 to 1990. The record does not show that the expenses deferred (see MEC Exhibit 114, Schedule 8) would be duplicated in 1990, resulting in a double recovery.

Accumulated Deferred Income Taxes

250. For purposes of calculating income tax expense, it is appropriate to use a combined Minnesota and federal tax rate (40.27%) so that Minnesota ratepayers bear the burden of Minnesota income tax.

251. NSP used a Total Company composite tax rate of 39.41% for calculating accumulated deferred income taxes in this case. MEC contends that the result of using the Total Company composite tax rate for accumulated deferred income taxes is that NSP's Minnesota jurisdictional rate base is overstated. MEC maintains that NSP must calculate jurisdictional accumulated deferred income taxes with the Minnesota jurisdictional tax rate, which would decrease NSP's jurisdictional rate base, thus reducing NSP's revenue requirement.

252. For purposes of calculating deferred income taxes, it is appropriate to use NSP's overall corporate rate. Such treatment properly reflects the fact that NSP's total system benefits customers in all jurisdictions and is consistent with the way in which NSP maintains its books. Further, it is important that the same tax rate be used to calculate deferred income tax and accumulated deferred income tax. The use of NSP's corporate composite rate to calculate accumulated deferred income tax is appropriate.

MOTIONS TO DISMISS, TO EXCLUDE TESTIMONY AND EXHIBITS AND TO COMPEL DISCOVERY

253. On April 4, 1990, the Department of Public Service and Office of the Attorney General filed a Joint Motion to Dismiss NSP's November 2, 1989, filing for a general rate increase. North Star and MEC joined in the Motion. That Motion was denied orally at the evidentiary hearing. The Administrative Law Judge indicated at the time of the denial that he would continue taking the Motion to Dismiss under advisement, and the DPS and North Star renewed the Motion on briefs.

The Joint Motion of the Department of Public Service and the Office of the Attorney General to dismiss Northern States Power Company's November 2, 1989, filing for a general rate increase is DENIED.

254. The DPS and OAG filed a Joint Motion on April 4, 1990, to Exclude specific portions of Direct and Rebuttal Testimony of certain of NSP's witnesses, and the entirety of the Rebuttal Testimony of certain of NSP's witnesses. The Motions were ruled upon orally at the evidentiary hearing and in a telephone conference on April 27, 1990. The rulings of April 27 were reduced to writing on April 30, 1990. In his rulings, the Administrative Law Judge granted the Motions to Exclude in part and denied them in part.

As part of its Initial Brief, the DPS renewed its Motions to Exclude in their entirety, seeking exclusion of all portions of testimony not excluded by earlier rulings of the Administrative Law Judge.

The renewed Motion to Exclude of the Department of Public Service is DENIED.

255. At the evidentiary hearing, after the Administrative Law Judge granted in part and denied in part the Joint Motion to Exclude portions of the testimony of NSP witness Ronald Clough, the DPS made a Motion to Strike his remaining prefiled testimony, all of his cross-examination and the exhibits sponsored by him or introduced through him (NSP Exhibits 31, 32, 35, 36, 37 and MEC Exhibit 33) on the ground that the witness was incompetent to testify. The Motion to Strike was denied orally at the hearing. During the briefing period, the DPS has renewed its Motion to Strike.

The renewed Department of Public Service Motion to Strike all testimony, written and oral, and all documents introduced to the record through NSP witness Ronald Clough is DENIED.

256. North Star filed a Motion to Compel Discovery, which Motion was denied in writing on May 11, 1990. In its Initial Brief, North Star renewed its Motion.

The renewed North Star Steel Motion to Compel Discovery is DENIED.

257. As part of its Initial Brief, North Star noted that the Administrative Law Judge, in his May 11, 1990, rulings, did not specifically address NSS Request 2.47, which sought NSP's confidential five-year forecast that it provides to rating agencies.

North Star Steel's Motion to Compel a Response to NSS Request 2.47 is DENIED.

258. In its Initial Brief, North Star "incorporated by reference" its letter to the Administrative Law Judge of April 9, 1990, in which it "urged" the Judge to order NSP to respond to NSS Requests 6.1, 8.2, 8.5 (b) and 9.14. The Administrative Law Judge interprets North Star's incorporation by reference of its April 9, 1990, letter to constitute a Motion to Compel Responses to the NSS Requests.

North Star Steel's Motion to Compel Responses to NSS Requests 6.1, 8.2, 8.5 (b) and 9.14 is DENIED.

## ADJUSTMENTS TO PLANT AND CONSTRUCTION WORK IN PROGRESS AND OPERATING EXPENSES

259. The Department of Public Service's recommended downward adjustment of 23.08% to NSP's 1990 capital expenditures budget is inappropriate and should not be adopted.

260. The Department of Public Service's recommended downward adjustment of 5.3% to NSP's allowed test year operating expenses is inappropriate and should not be adopted.

261. MEC's recommended "normalizing" adjustment to NSP's budget forecast, adjusting operating expenses downward according to the Consumer Price Index, which would result in a $20,108,000 reduction in NSP's operating expenses, is inappropriate and should not be adopted.

## DSN FINANCIAL INCENTIVE STIPULATION

262. NSP, DPS and OAG jointly entered a Demand Side Management (DSM) Financial Incentive Stipulation. The Stipulation calls for a DSM Financial Incentives Mechanism which is designed to help remove existing financial disincentives for utilities to pursue DSM activities. Under the Stipulation,

Conservation Improvement Program (CIP) expenditures are divided into two categories: conservation strategy; and load management and research and development programs. Separate financial treatments for these two categories are then applied, recognizing the differences in the types of expenditures and the impacts of these expenditures.

263. With respect to the allowed return on the unamortized balance of conservation strategy expenditures, the Stipulation adds a bonus of five percent over the authorized rate of return on common equity.

264. The Administrative Law Judge has treated the DSM Financial Incentives Stipulation as an evidentiary item for purposes of the record. All non-signatory parties were given the opportunity to present evidence and/or file Briefs in opposition to any of its terms.

265. The DSM Financial Incentive Stipulation (NSP Exhibit 140) is supported by substantial evidence in all respects. Adoption of the Stipulation (attached hereto as Appendix A) would be in the public interest. It is appropriate to adopt the demand side management Financial Incentives Stipulation of Northern States Power Company, the Department of Public Service and the Office of Attorney General for implementation during the test year.

ADJUSTMENTS TO RATE BASE AND INCOME STATEMENT, REVENUE REQUIREMENT SUMMARY

266. NSP's proposed final rate base is $2,364,867,000. Based upon the above Findings, NSP's rate base should be adjusted downward by $7,942,000, as follows:

| Name | Adjustment |
|---|---|
| Pathfinder | ($3,412,000) |
| Graystone | ($ 979,000) |
| Economic Development | ($ 897,000) |
| Unburned Nuclear Fuel | $ 497,000 |
| Gain on Land Sold - Chippewa Flowage | ($3,151,000) |
| | ($7,942,000) |

267. NSP's average rate base for the test year is $2,356,925,000, as computed in the preceding Finding.

268. NSP proposes an amount of $168,390,000 in net operating income ($161,155,000) plus allowance for funds used during construction ($6,835,000), totalling $168,390,000 in income to be applied toward its revenue requirement. NSP's test year operating income should be increased by $5,808,000, as follows (figures are net after taxes):

| | |
|---|---|
| Pathfinder | $1,338,000 |
| Graystone | $ 33,000 |
| Economic Development | $ 271,000 |
| Unburned Nuclear Fule | $ 849,000 |

| | |
|---|---|
| Midwest Compact Fee | $ 296,000 |
| NRC License Fee | $ 664,000 |
| Chippewa Land Sale | $1,576,000 |
| Minnesota Power Capacity Purchases | $ 644,000 |
| Marketing Programs | $ 137,000 |
| | $5,808,000 |

As a consequence, NSP's test year operating income is $174,198,000.

269. As a result of the preceding Findings regarding cost of capital, rate base and test year operating income, the revenue deficiency of Northern States Power Company for the test year is $84,013,000, calculated as follows:

| | |
|---|---|
| Rate Base | $2,356,925,000 |
| Rate of Return | 9.52% |
| Required Operating Income | $224,379,000 |
| Test Year Operating Income | $174,198,000 |
| Income Deficiency | $ 50,181,000 |
| Gross Revenue Conversion Factor | 1.674201 |
| Gross Revenue Deficiency | $84,013,000 |

NSP originally filed for a general rate increase of $120,782,000, or 10.2% overall. The gross revenue deficiency of $84,013,000 represents a 7.1% overall rate increase for NSP.

## CONCEPTS TO GOVERN

270. It is the intention of the Administrative Law Judge that the concepts set forth in the Findings herein should govern the mathematical and computational aspects of the Findings and Conclusions. Any mathematical or computational errors are unintentional and should be corrected to conform to the concepts expressed in the Findings and Conclusions.

## PART II - CONSERVATION AND RATE DESIGN ISSUES

271. Due to the extended scope of this proceeding, the need to afford the parties an adequate period for filing exceptions and the time within which the Commission must issue its final Order, the Findings of Fact, Conclusions and Recommendations of the Administrative Law Judge will be issued in two parts. This Part I includes all issues other than rate design, conservation issues that do not have an impact on the requested revenue requirement, and discussion of the Administrative Law Judge's Findings on the Joint Motion to Dismiss and "across the board"-type adjustments. Part II will consider all remaining issues and will include a recommended Order.

Based upon the foregoing Findings of Fact, the Administrative Law Judge makes the following:

## CONCLUSIONS

1. The Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this hearing pursuant to Minn. Stat. Ch. 216B and 14.57 - 14.62. and Minn. Rules Part 1400.5100 - .8300.

2. Any of the above Findings of Fact more properly considered Conclusions of Law are hereby adopted as such.

3. The Public Utilities Commission (PUC) gave proper notice of the hearing in this matter, has fulfilled all relevant substantive and procedural requirements of law or rule and has the authority to take the action proposed.

4. The quantum of proof necessary to establish the facts supporting the reasonableness of the proposed rate change is proof by a preponderance of the evidence.

5. The proper test year for use in this proceeding is the twelve-month period between January 1, 1990 and December 31, 1990.

6. The appropriate capital structure for use in this proceeding is 39.09% long-term debt, 1.31% short-term debt, 3.07% Tax Benefit Transfer (TBT) lease monies, 9.50% preferred stock and 47.03% common equity.

7. The cost of long-term debt of the Company for use in this proceeding is 8.48%. 8. The cost of short-term debt to be used in determining the Company's cost of capital is 7.68%.

9. The Company's cost of preferred stock to be used in determining its cost of capital is 5.90%.

10. It is appropriate to treat Tax Benefit Transfer monies as no-cost debt in this proceeding.

11. The appropriate cost of common equity for NSP in this proceeding is 11.80%.

12. The appropriate overall rate of return to be allowed the Company in this proceeding is 9.52%.

13. It is appropriate to reject the Company's proposal for the ratepayers to provide funds or reimburse expenses associated with decommissioning of NSP's Pathfinder Atomic Power Plant in Sioux Falls, South Dakota.

14. It is appropriate to classify NSP's investment in the Graystone Project as a Preliminary Survey and Investigation (PS&I) item. The Graystone investment should be excluded from the rate base and operating expenses during the test year.

15. It is appropriate to exclude from rate base and operating expenses the Company's proposed economic development investment expenditures.

16. It is appropriate to reject NSP's proposal for recovery of unburned nuclear fuel during the test year.

17. NSP's proposal for expensing of repairs on the Manitoba Hydro Line is reasonable.

18. NSP's proposal to amortize the cost of the replacement rotor at the Allan S. King generating plant, and that the unamortized balance be included in rate base, is reasonable.

19. It is appropriate to grant NSP's request for a two-year amortization period for rate case expenses.

20. NSP's proposed methodology for accrual of the expenes for decommissioning of its Monticello, Prairie Island 1 and Prairie Island 2 nuclear power plants is reasonable.

21. It is appropriate to reduce NSP's proposal for the amount of expenditures to pay its Midwest Compact Fee contribution by $585,000, as recommended by the Department of Public Service.

22. It is appropriate to reduce NSP's requested amount for its Nuclear Regulatory Commission (NRC) license fee by $1,112,000.

23. The Company has established that its system of matching 365 days of revenue and expenses is just and reasonable. It would be inappropriate to adopt the proposal of the Office of Attorney General regarding adjustment of unbilled revenues.
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24. It is appropriate for Minnesota ratepayers to share a fair proportion of NSP's profit in the sale of its Chippewa Flowage land in Wisconsin. An adjustment during the test year to reduce NSP's rate base by $3,151,000 and increase its net operating income by $1,576,000 would reflect the appropriate treatment during the test year.

25. It is appropriate to allow a 9% escalation factor in NSP's estimated property tax accrual for the test year.

26. It is inappropriate to allow NSP to recover 1991 expenses during the test year (calendar year 1990) for its purchase of capacity from Minnesota Power. Test year operating income should be raised by $644,000 to account for this adjustment.

27. It is appropriate to disallow recovery from ratepayers of an additional $93,000 in research and development costs during the test year for NSP's advanced combined cycle project.

28. The Company's incentive compensation plan is reasonable and not against public policy. No adjustment in test year revenues should be made because of the incentive compensation plan's features.

29. It is appropriate to adopt the Company's proposal to include Tax Benefit Transfer (TBT) lease monies in the Company's capital structure as an item of no-cost capital contributed by

the shareholders.

30. It is appropriate to disallow recovery for NSP's cooking, floodlighting, security lighting and heat storage projects. A downward adjustment of NSP's marketing expenses of $230,000 is appropriate to reflect that adjustment.

31. It is inappropriate to adopt the adjustment proposed by Minnesota Energy Consumers (MEC) of $2,997,000 in operating expenses for expenses deferred from 1989 to 1990.

32. For purposes of calculating deferred and accumulated deferred income taxes in this proceeding, it is appropriate to use NSP's overall corporate rate of 39.41%

33. It is appropriate to deny the Joint Motion of the Department of Public Service and the Office of the Attorney General to dismiss Northern States Power Company's general rate case filing of November 2, 1989.

34. It is appropriate to reject the Department of Public Service's recommended downward adjustment of 23.08% to NSP's 1990 capital expenditures budget.

35. It is appropriate to reject the Department of Public Service's recommended downward adjustment of 5.3% to NSP's allowed test year operating expenses.

36. It is appropriate to reject the MEC's recommended normalizing adjustment to NSP's budget forecast, which would adjust operating expenses downward according to the Consumer Price Index.

37. It is appropriate to adopt the Demand Side Management Financial Incentive Stipulation of the Company, DPS and the OAG.

38. It is appropriate to set NSP's average rate base for the test year at $2,356,925,000.

39. It is appropriate to set NSP's test year operating income at $174,198,000.

40. The appropriate revenue deficiency for Northern States Power Company during the test year is $84,013,000.

Dated this          day of July, 1990.

RICHARD C. LUIS
Administrative Law Judge

Reported: Harold Reiner & Associates.

7-2500-4230-2
E-002/GR-89-865

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Petition of Northern States Power Company (NSP) for Authority to Increase Its Rates for Electric Service in Minnesota

ADDITIONAL FINDING OF FACT AND CONCLUSIONS - PART I (REVENUE REQUIREMENTS)

On July 13, 1990, the Administrative Law Judge issued Part I of his Findings of Fact, Conclusions and Recommendation in the above-entitled matter, which Report contained 271 Findings of Fact and 40 Conclusions. After further review of that Report, the Administrative Law Judge finds it appropriate to add one Finding of Fact and three Conclusions to his July 13 Report.

Based upon all the proceedings herein, the Administrative Law Judge makes the following additional:

FINDING OF FACT

272. In its November 2, 1989 filing, the Company submitted a test year sales forecast that resulted in base electric sales revenues for the Minnesota jurisdiction of $1,176,796,000 (under present rates) and $1,296,417,000 (under final proposed rates).

The Department of Public Service conducted its own forecast of NSP's sales. Both forecasts are based on estimates of energy sales during the test year. The DPS filed testimony indicating that the Department's forecast resulted in a net decrease in NSP's forecasted total revenues and a net increase in NSP's forecasted revenue deficiency. The Department has taken the position that NSP has not overstated its revenue deficiency by understating the revenues resulting from its forecasted sales. The Department recommends that NSP's sales forecast, as filed in its original testimony, be accepted by the PUC for use in this proceeding. DPS Ex. 209.

Based upon Findings of Fact 1 - 272, the Administrative Law Judge makes the following additional:

## CONCLUSIONS

41. The appropriate dividend yield component in cost of equity for the Company during the test year is 6.5%.

42. The appropriate growth rate component in the Company's cost of equity for the test year is 5.3%.

43. It is appropriate for the Commission to adopt NSP's test year sales forecast.

Dated this       day of July, 1990.

RICHARD C. LUIS
Administrative Law Judge

NORTHERN STATES POWER SERVICE LIST
7-2500-4230-2, E-002/GR-89-865
7/13/90

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July 16, 1990

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Re: In the Matter of the Petition of Northern States Power Company (NSP) for Authority to Increase Its Rates for Electric Service in Minnesota; PUC Docket No. E-002/GR-89-865; OAH Docket No. 7-2500-4230-2.

Dear Mr. Lancaster:

Enclosed herewith and served upon you please find Additional Finding of Fact and Conclusions - Part I (Revenue Requirements) of the Administrative Law Judge in the above-referenced matter.

Very truly yours,

RICHARD C. LUIS
Administrative Law Judge

Telephone: 612/349-2542

sh
Enc.
cc: All Parties and Counsel

NORTHERN STATES POWER SERVICE LIST
7-2500-4230-2, E-002/GR-89-865
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